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Bansal et al.

(10) **Patent No.:** **US 10,006,262 B2**
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(54) **CONTINUOUS FLOW SYSTEM FOR DRILLING OIL AND GAS WELLS**

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(*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 502 days.

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(22) Filed: **Feb. 9, 2015**

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(51) **Int. Cl.**
E21B 21/10 (2006.01)
E21B 19/16 (2006.01)
(Continued)

(52) **U.S. Cl.**
CPC **E21B 21/106** (2013.01); **E21B 3/00** (2013.01); **E21B 19/16** (2013.01); **E21B 21/06** (2013.01);
(Continued)

(58) **Field of Classification Search**
CPC E21B 3/00; E21B 21/106; E21B 19/16; E21B 19/165; E21B 2034/002;
(Continued)

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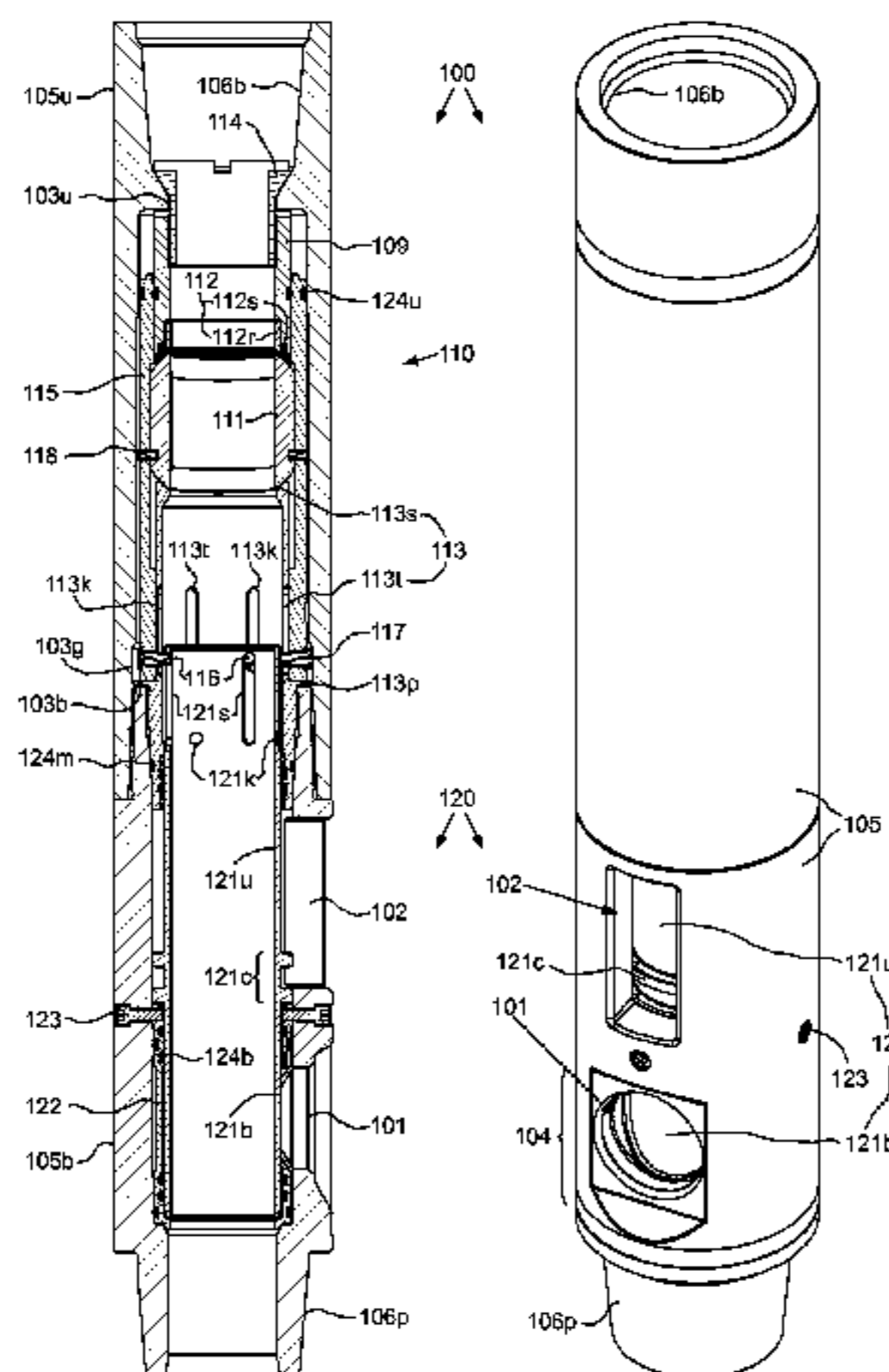
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(57) **ABSTRACT**
A flow sub for use with a drill string includes a tubular housing having a longitudinal bore therethrough and a flow port through a wall thereof and a ball. The ball is disposed in the housing above the flow port, has a bore therethrough, and is rotatable relative to the housing between an open position where the ball bore is aligned with the housing bore and a closed position where a wall of the ball blocks the housing bore. The flow sub further includes a seat disposed in the housing above the ball for sealing against the ball wall in the closed position and a sleeve disposed in the housing and movable between an open position where the flow port is exposed to the housing bore and a closed position where a wall of the sleeve is disposed between the flow port and the housing bore.

28 Claims, 27 Drawing Sheets



<p>(51) Int. Cl. <i>E21B 21/06</i> (2006.01) <i>E21B 3/00</i> (2006.01) <i>E21B 34/14</i> (2006.01) <i>E21B 34/00</i> (2006.01)</p> <p>(52) U.S. Cl. CPC <i>E21B 34/14</i> (2013.01); <i>E21B 2034/007</i> (2013.01)</p> <p>(58) Field of Classification Search CPC <i>E21B 2034/007</i>; <i>E21B 34/08</i>; <i>E21B 34/14</i>; <i>E21B 23/006</i> See application file for complete search history.</p> <p>(56) References Cited</p> <p style="padding-left: 40px;">U.S. PATENT DOCUMENTS</p> <p>2,102,555 A 12/1937 Dyer 2,158,356 A 5/1939 Dyer 2,202,192 A 5/1940 Cypher 2,224,657 A 12/1940 Rodgers 2,239,586 A 4/1941 Appleby 2,858,838 A 11/1958 Scaramucci 2,974,922 A 3/1961 Keitahn 3,036,590 A 5/1962 Knox 3,123,157 A 3/1964 Graham 3,268,017 A 8/1966 Yarbrough 3,298,385 A 1/1967 Jackson et al. 3,497,020 A 2/1970 Kammerer, Jr. et al. 3,559,739 A 2/1971 Hutchison 3,684,318 A 8/1972 Eckert et al. 3,877,529 A * 4/1975 Litchfield E21B 19/20 166/380 4,262,693 A * 4/1981 Giebeler E21B 21/106 137/494 4,310,050 A 1/1982 Bourgoyne, Jr. 4,315,553 A 2/1982 Stallings 4,377,179 A * 3/1983 Giebeler E21B 21/10 137/494 4,393,940 A 7/1983 Cooper et al. 4,448,267 A 5/1984 Crawford, III et al. 4,478,244 A 10/1984 Garrett 4,566,478 A 1/1986 Deaton 4,566,494 A 1/1986 Roche 5,159,981 A 11/1992 Le 5,482,119 A * 1/1996 Manke E21B 23/006 166/321 5,529,126 A 6/1996 Edwards 5,551,665 A 9/1996 Noack et al. 5,558,121 A 9/1996 Webster et al. 5,896,924 A 4/1999 Carmody et al. 5,988,220 A 11/1999 Sakaki 6,119,772 A 9/2000 Pruet 6,230,824 B1 5/2001 Peterman et al. 6,253,861 B1 7/2001 Carmichael et al. 6,315,051 B1 11/2001 Ayling 6,607,042 B2 8/2003 Hoyer et al. 6,622,791 B2 9/2003 Kelley et al. 6,668,684 B2 12/2003 Allen et al. 6,739,397 B2 5/2004 Ayling 7,028,585 B2 4/2006 Pietras et al. 7,028,586 B2 4/2006 Robichaux et al. 7,108,080 B2 9/2006 Tessari et al. 7,140,455 B2 11/2006 Walter et al. 7,163,064 B2 1/2007 Moncus et al. 7,219,722 B2 5/2007 Fincher et al. 7,308,952 B2 12/2007 Strazhgorodskiy 7,726,418 B2 6/2010 Ayling 7,758,019 B2 7/2010 Braddick 7,963,339 B2 6/2011 Cowie et al. 8,016,033 B2 * 9/2011 Iblings E21B 19/16 166/192 8,210,266 B2 7/2012 Younger et al. 8,403,293 B2 3/2013 Cowie et al. 8,505,635 B2 8/2013 Vatne 9,316,071 B2 * 4/2016 Feasey E21B 21/08</p>	<p>2004/0003490 A1 1/2004 Shahin et al. 2004/0020654 A1 2/2004 Milberger et al. 2004/0154835 A1 8/2004 Allen et al. 2004/0163809 A1 * 8/2004 Mayeu E21B 34/06 166/255.1 2006/0254822 A1 11/2006 Ayling 2006/0272825 A1 * 12/2006 Royer E21B 34/14 166/373 2006/0278434 A1 12/2006 Calderoni et al. 2009/0025930 A1 1/2009 Iblings et al. 2009/0205838 A1 * 8/2009 Springett E21B 21/01 166/380 2009/0242817 A1 10/2009 Strazhgorodskiy 2009/0272580 A1 11/2009 Dolman et al. 2010/0084142 A1 4/2010 Calderoni et al. 2010/0096190 A1 4/2010 Younger et al. 2010/0155143 A1 * 6/2010 Braddick E21B 19/16 175/218 2010/0200299 A1 * 8/2010 Vatne E21B 19/16 175/57 2010/0252272 A1 * 10/2010 Haughom E21B 21/106 166/373 2010/0276153 A1 * 11/2010 Gette E21B 33/04 166/351 2010/0300543 A1 12/2010 Braddick 2011/0155379 A1 * 6/2011 Bailey E21B 19/16 166/324 2011/0203670 A1 * 8/2011 Braddick E21B 21/106 137/1 2011/0308860 A1 * 12/2011 deBoer E21B 17/00 175/57 2012/0018229 A1 1/2012 Leuchtenberg et al. 2013/0068532 A1 * 3/2013 Bansal E21B 21/10 175/218 2013/0112428 A1 5/2013 Weir et al. 2013/0118758 A1 5/2013 Caminari 2013/0269951 A1 * 10/2013 Tahoun E21B 34/06 166/373 2014/0124195 A1 * 5/2014 Tahoun E21B 21/103 166/250.01 2014/0158433 A1 * 6/2014 Bisset E21B 21/103 175/218 2014/0166364 A1 * 6/2014 Blue E21B 21/08 175/48 2014/0202767 A1 * 7/2014 Feasey E21B 21/08 175/57 2015/0136396 A1 * 5/2015 Turley E21B 23/10 166/285 2015/0240582 A1 * 8/2015 Bansal E21B 3/00 175/57</p> <p style="text-align: center;">FOREIGN PATENT DOCUMENTS</p> <p>EP 0606981 A1 7/1994 EP 1331356 A2 7/2003 GB 2118998 A 11/1983 GB 2159194 A 11/1985 GB 2220963 A 1/1990 GB 2325682 A 12/1998 GB 2378199 A 2/2003 GB 2426274 A 11/2006 GB 2464216 A * 4/2010 E21B 23/04 SU 979616 A1 12/1982 WO 2005/080745 A1 9/2005 WO 2009/022914 A1 2/2009 WO 2010/112933 A2 10/2010 WO 2012/085597 A2 6/2012</p> <p style="text-align: center;">OTHER PUBLICATIONS</p> <p>Australian Patent Examination Report dated Dec. 18, 2015, for Australian Patent Application No. 2015200783. Cunningham et al.—A New Continuous Flow System (CFS) for Managed Pressure Drilling, paper prepared for presentation at the 2014 IADC/SPE Drilling Conference and Exhibition held in Fort Worth, Texas, Mar. 4-6, 2014, IADC/SPE/-168030-MS, 7 pages.</p>
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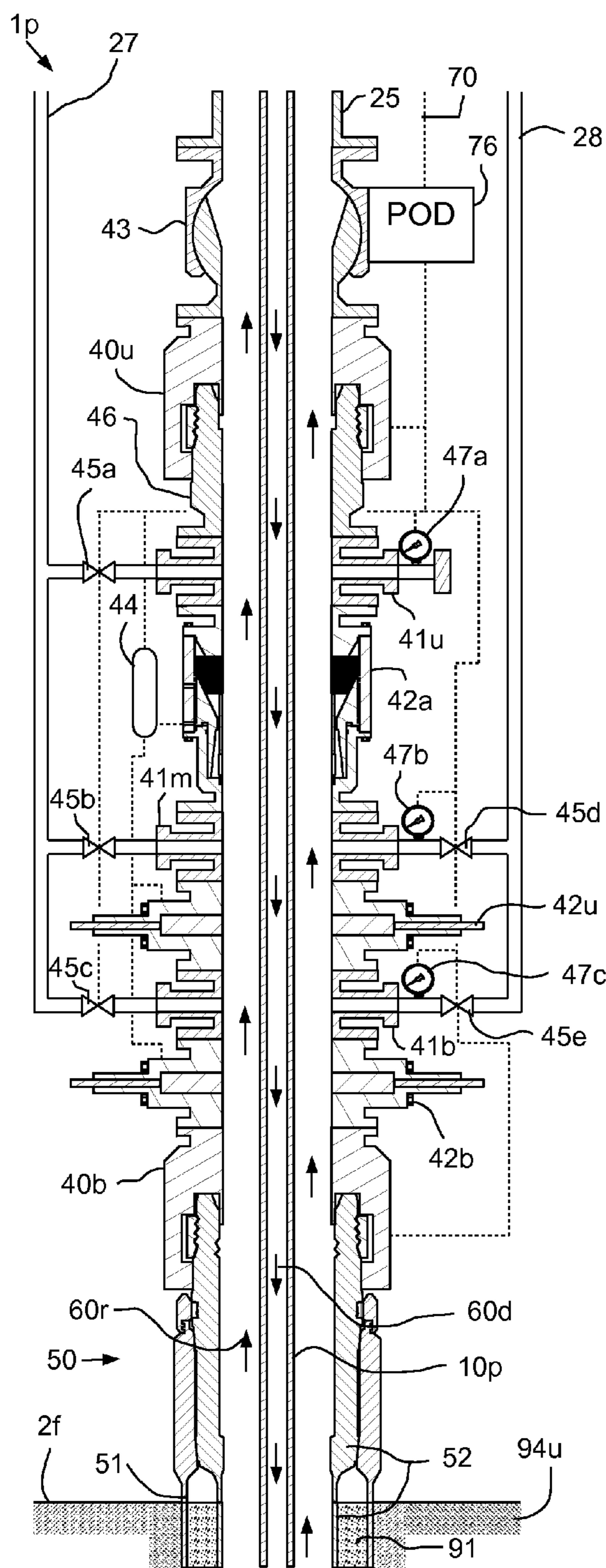


FIG. 1B

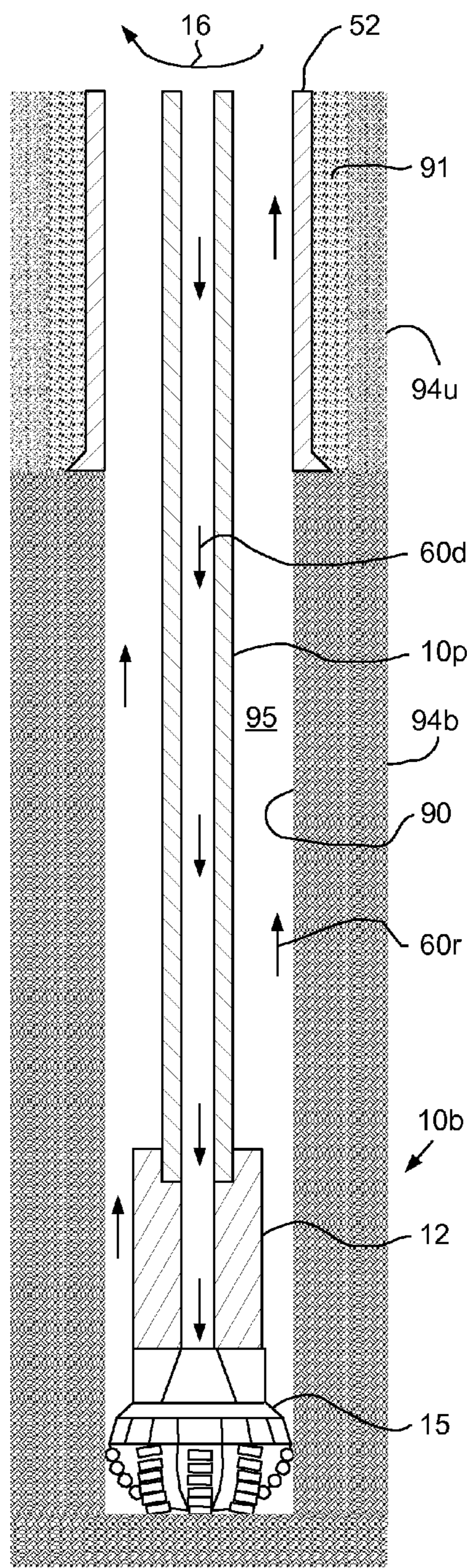


FIG. 1C

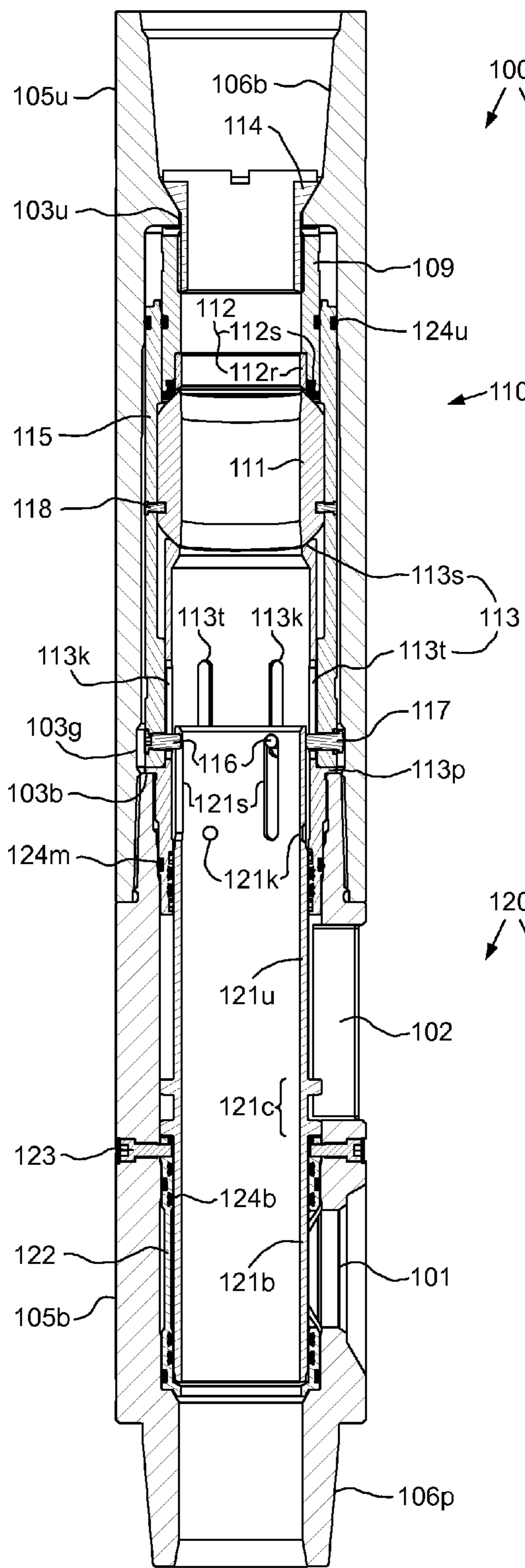


FIG. 2A

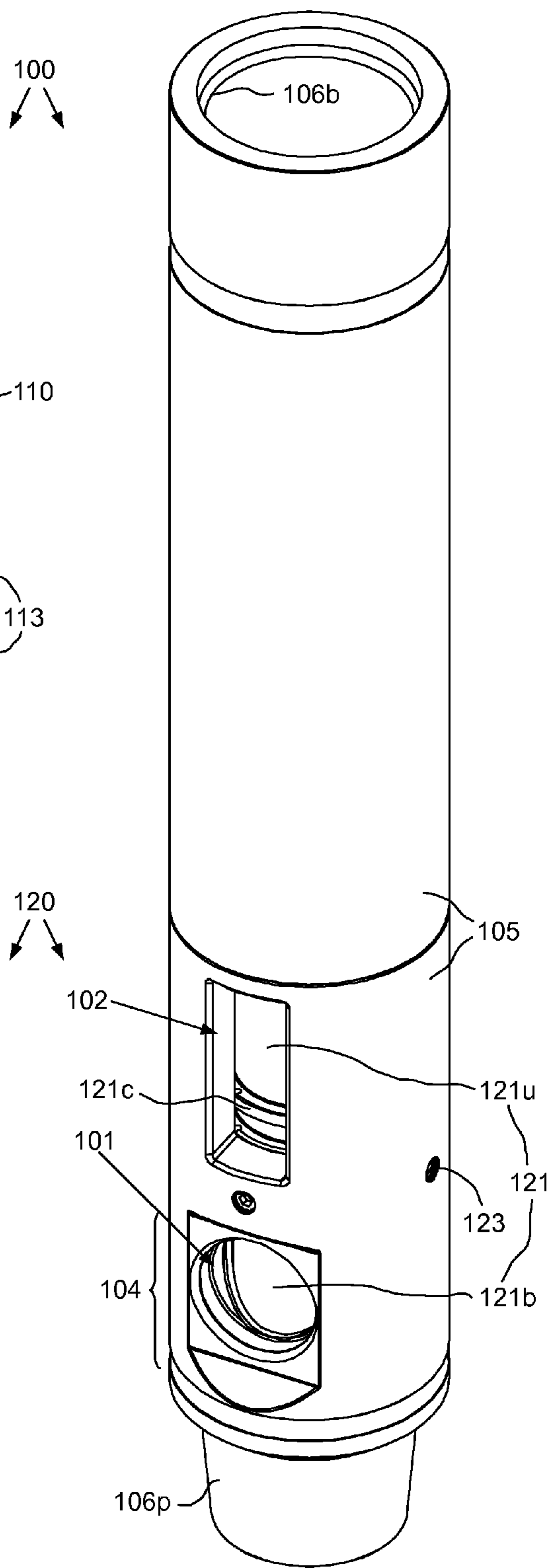
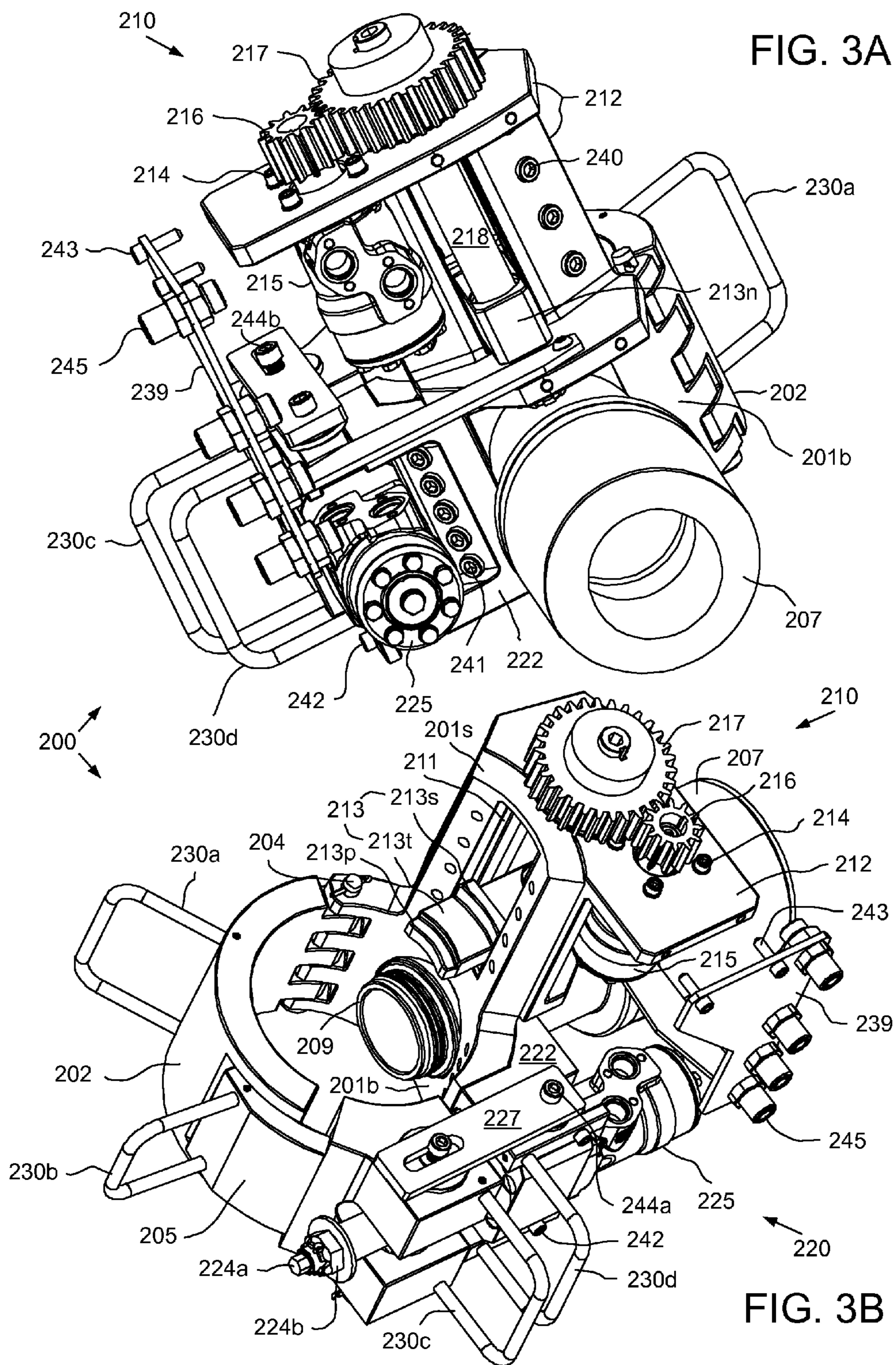


FIG. 2B



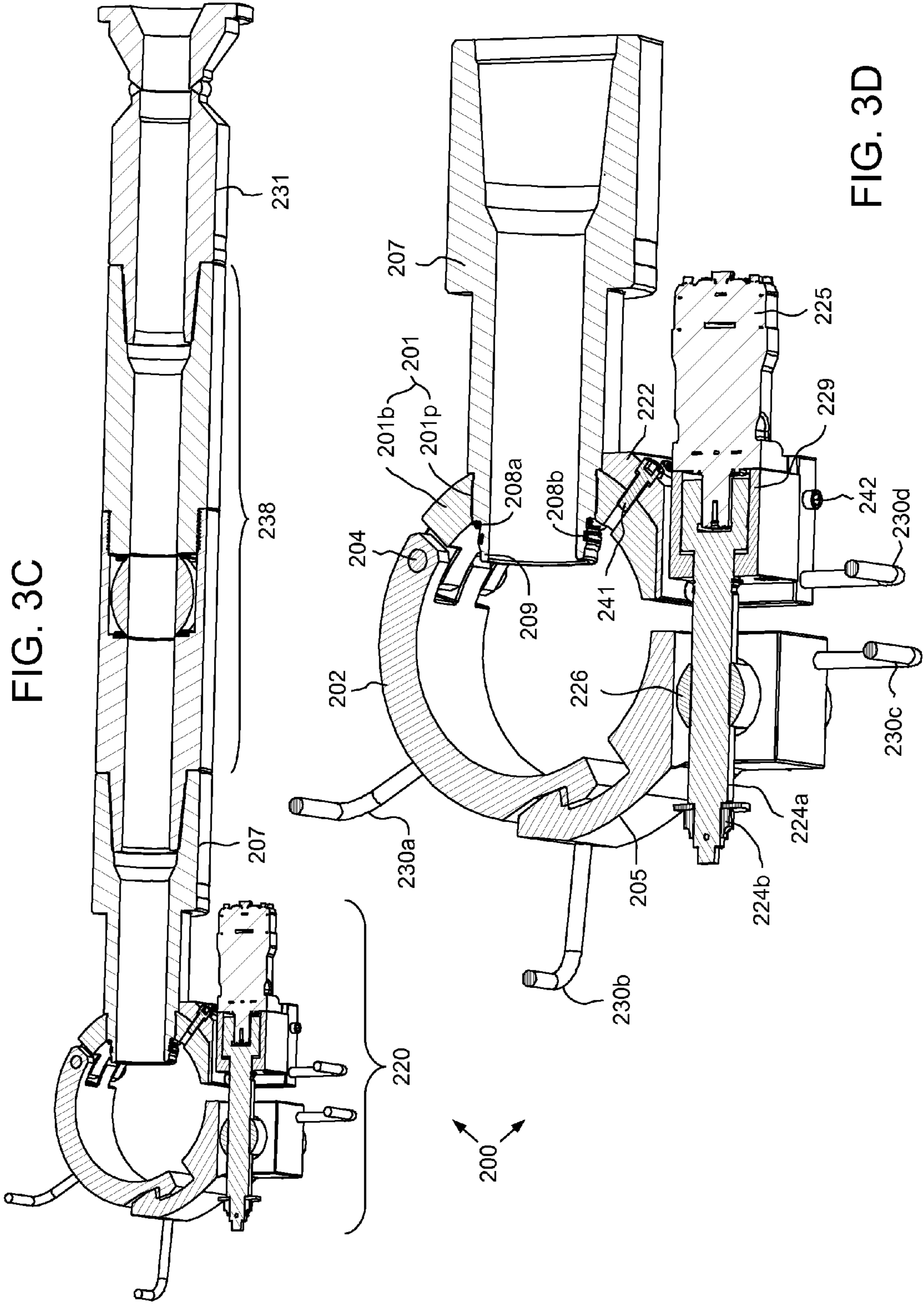


FIG. 3C

FIG. 3D

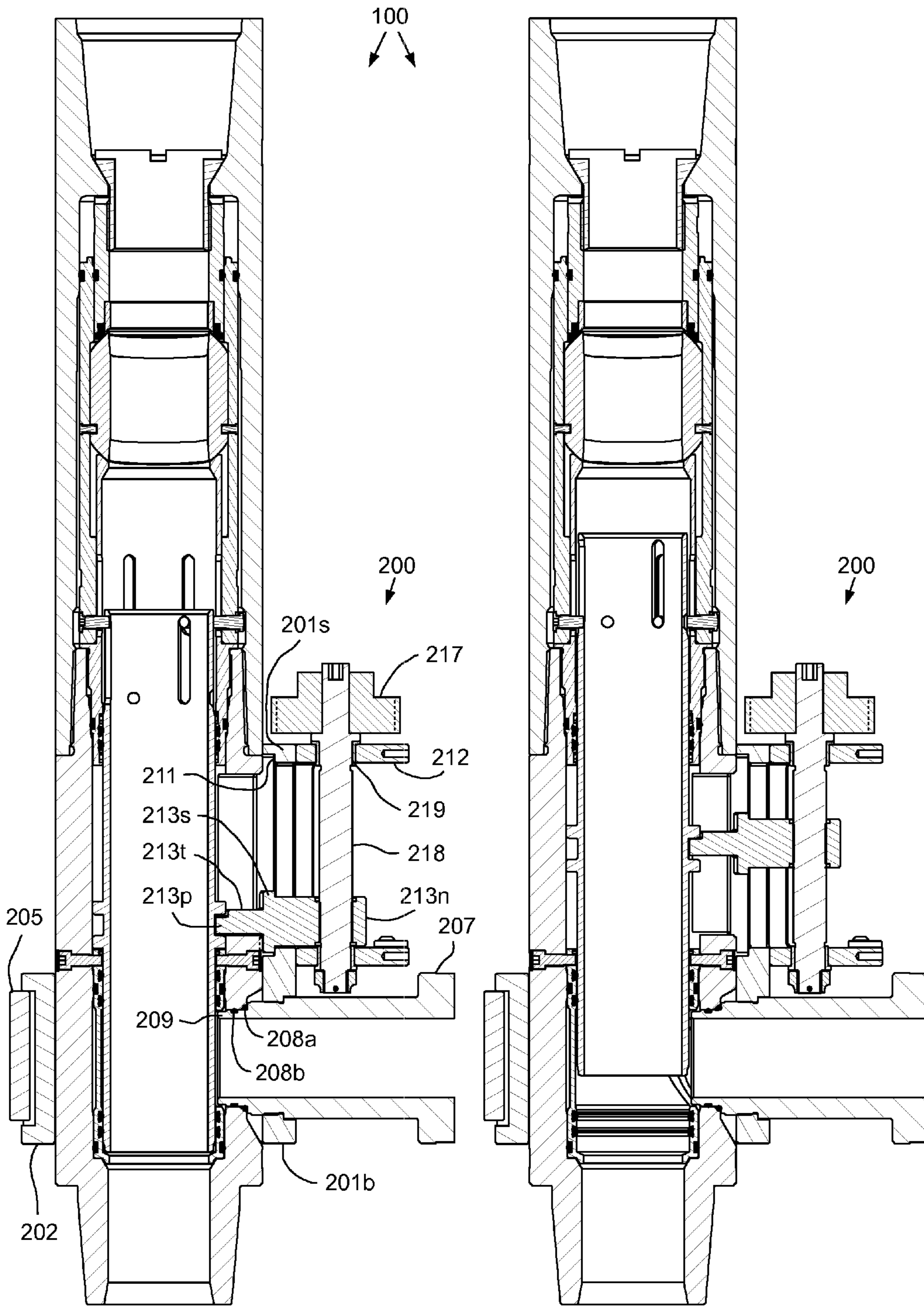


FIG. 4A

FIG. 4B

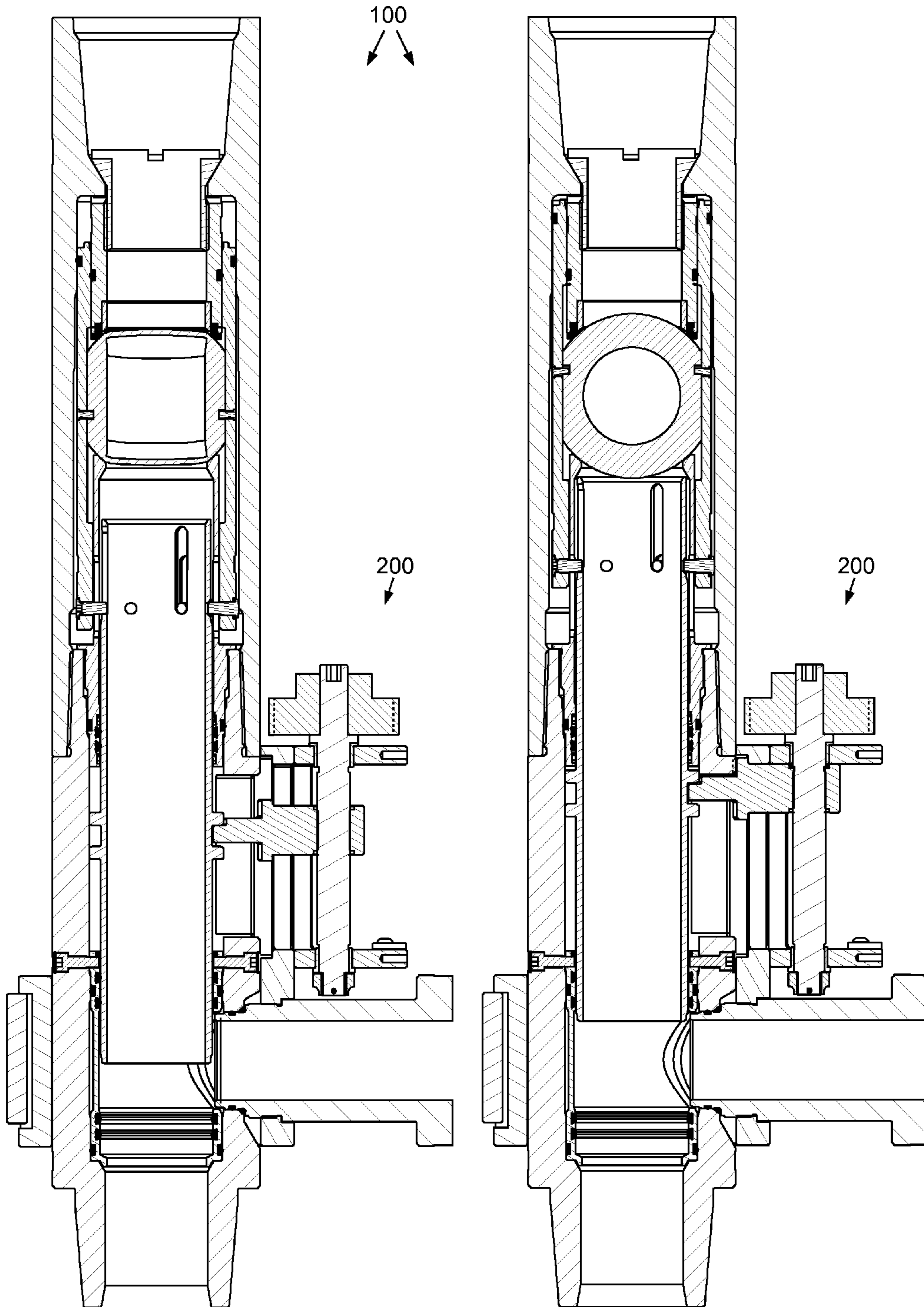


FIG. 4C

FIG. 4D

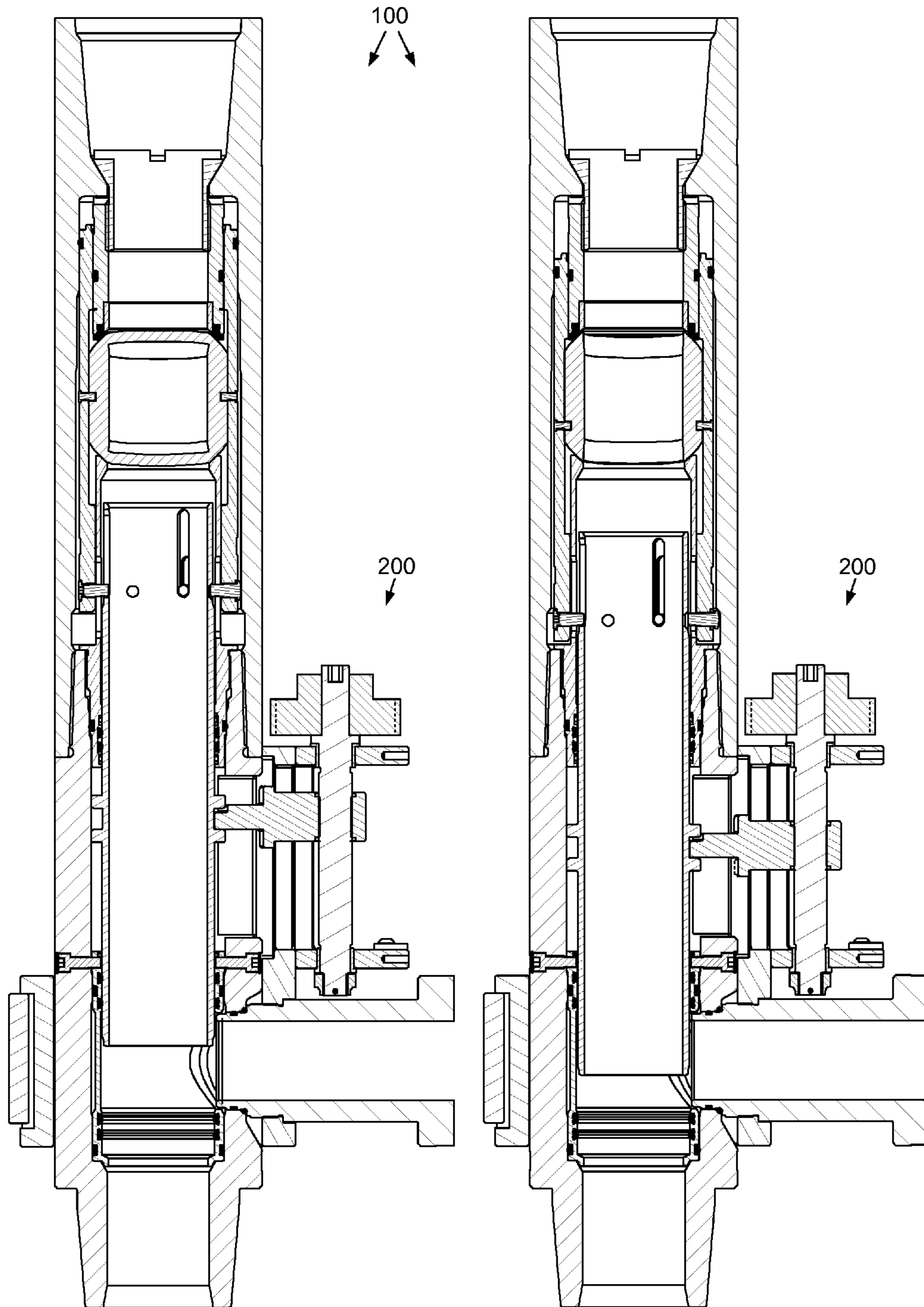


FIG. 4E

FIG. 4F

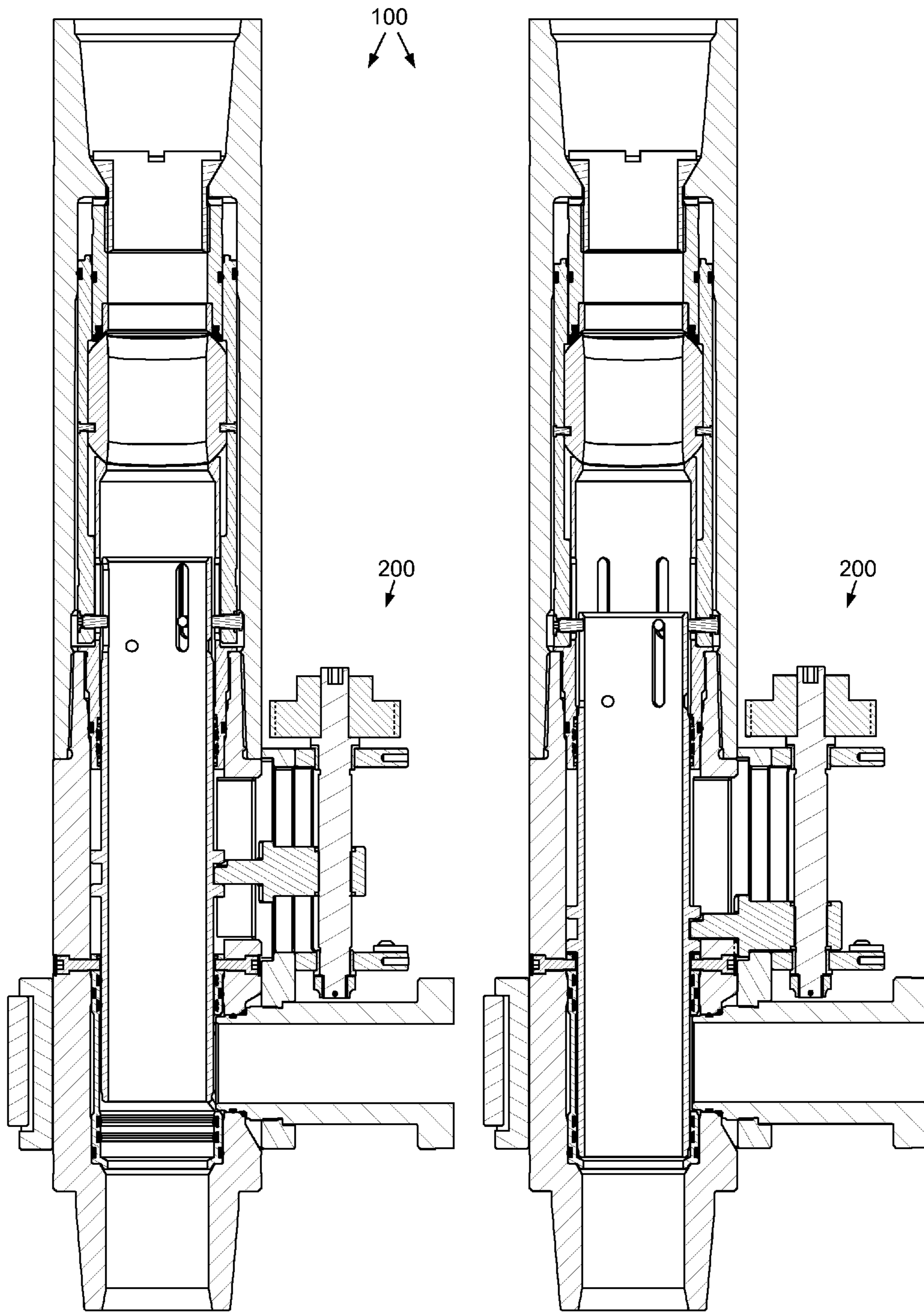


FIG. 4G

FIG. 4H

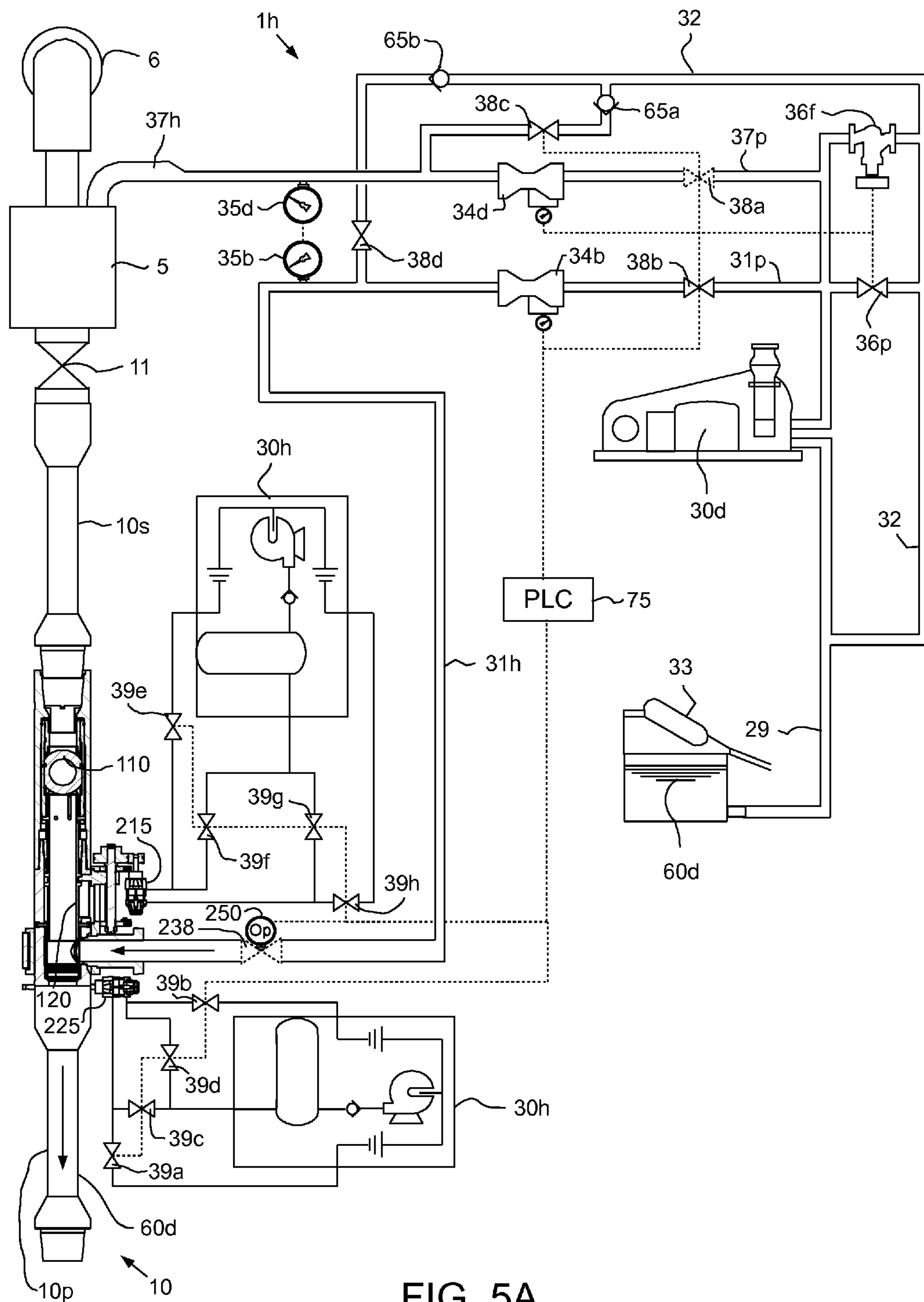


FIG. 5A

Operation	Action	38a	38b	38c	38d	238	36p	36f
Drilling	Mud pumped via top drive	Open	Closed	Closed	Open	Closed	Auto	Auto
Install clamp	Operate band actuator	Open	Closed	Closed	Open	Closed	Auto	Auto
Test clamp seal	Monitor pressure	Open	<u>Open</u>	Closed	<u>Closed</u>	<u>Open</u>	Auto	Auto
Switch mud flow to clamp	Operate CFS actuator	Open	Open	Closed	Closed	Open	Auto	Auto
Bleed top drive		<u>Closed</u>	Open	<u>Open</u>	Closed	Open	Auto	Auto
Test bore valve	Monitor pressure	Closed	Open	<u>Closed</u>	Closed	Open	Auto	Auto
Add stand to drill string	Operate top drive	Closed	Open	<u>Open</u>	Closed	Open	Auto	Auto
Pressurize added stand		<u>Open</u>	Open	<u>Closed</u>	Closed	Open	Auto	Auto
Switch mud flow to top drive	Operate CFS actuator	Open	Open	Closed	Closed	Open	Auto	Auto
Bleed clamp		Open	<u>Closed</u>	Closed	<u>Open</u>	Open	Auto	Auto
Test port valve	Monitor pressure	Open	Closed	Closed	<u>Closed</u>	Open	Auto	Auto
Remove clamp	Operate band actuator	Open	Closed	Closed	<u>Open</u>	<u>Closed</u>	Auto	Auto
Resume drilling	Mud pumped via top drive	Open	Closed	Closed	Open	Closed	Auto	Auto
Overpressure							Open	Auto
Overflow							Auto	Open

FIG. 5B

Operation	Action	39a	39b	39c	39d	39e	39f	39g	39h
Drilling	Mud pumped via top drive	Closed	Closed	Closed	Closed	Closed	Closed	Closed	Closed
Install clamp	Operate band actuator	<u>Open</u>	Closed	Closed	<u>Open</u>	Closed	Closed	Closed	Closed
Test clamp seal	Monitor pressure	<u>Locked</u>	<u>Locked</u>	<u>Locked</u>	<u>Locked</u>	Closed	Closed	Closed	Closed
Switch mud flow to clamp	Operate CFS actuator	Locked	Locked	Locked	Locked	Closed	<u>Open</u>	Closed	<u>Open</u>
Bleed top drive		Locked	Locked	Locked	Locked	<u>Locked</u>	<u>Locked</u>	<u>Locked</u>	<u>Locked</u>
Test bore valve	Monitor pressure	Locked	Locked	Locked	Locked	Locked	Locked	Locked	Locked
Add stand to drill string	Operate top drive	Locked	Locked	Locked	Locked	Locked	Locked	Locked	Locked
Pressurize added stand		Locked	Locked	Locked	Locked	Locked	Locked	Locked	Locked
Switch mud flow to top drive	Operate CFS actuator	Locked	Locked	Locked	Locked	<u>Open</u>	<u>Closed</u>	<u>Open</u>	<u>Closed</u>
Bleed clamp		Locked	Locked	Locked	Locked	<u>Closed</u>	Closed	<u>Closed</u>	Closed
Test port valve	Monitor pressure	Locked	Locked	Locked	Locked	Closed	Closed	Closed	Closed
Remove clamp	Operate band actuator	<u>Closed</u>	<u>Open</u>	<u>Open</u>	<u>Closed</u>	Closed	Closed	Closed	Closed
Resume drilling	Mud pumped via top drive	Closed	<u>Closed</u>	<u>Closed</u>	Closed	Closed	Closed	Closed	Closed

FIG. 5C

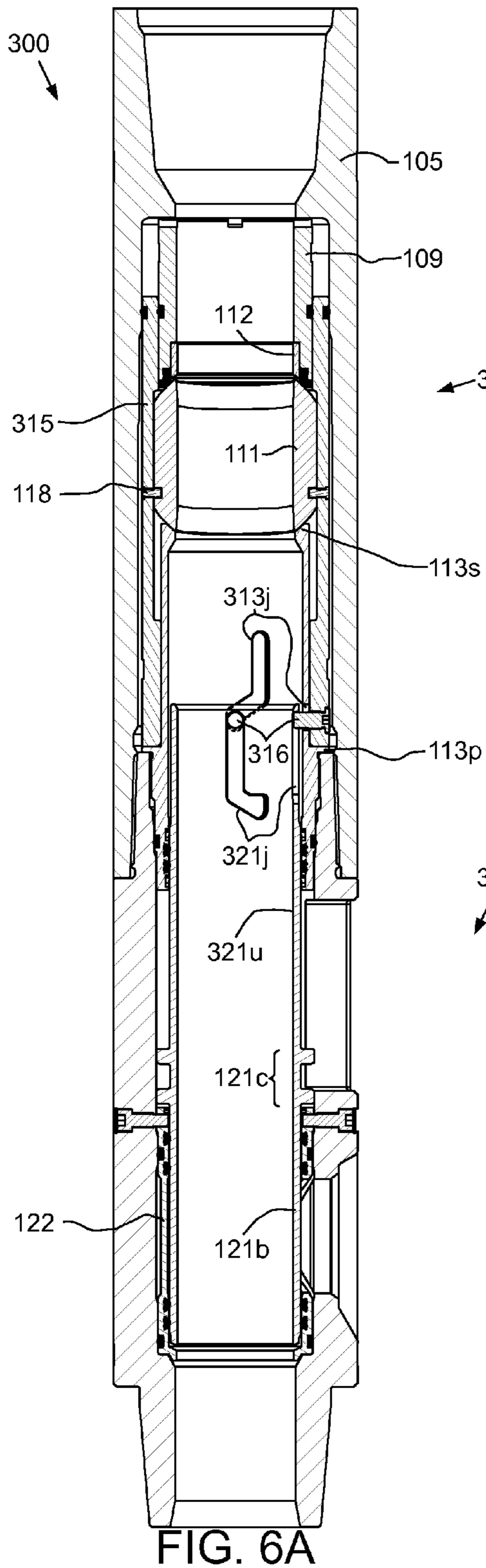


FIG. 6A

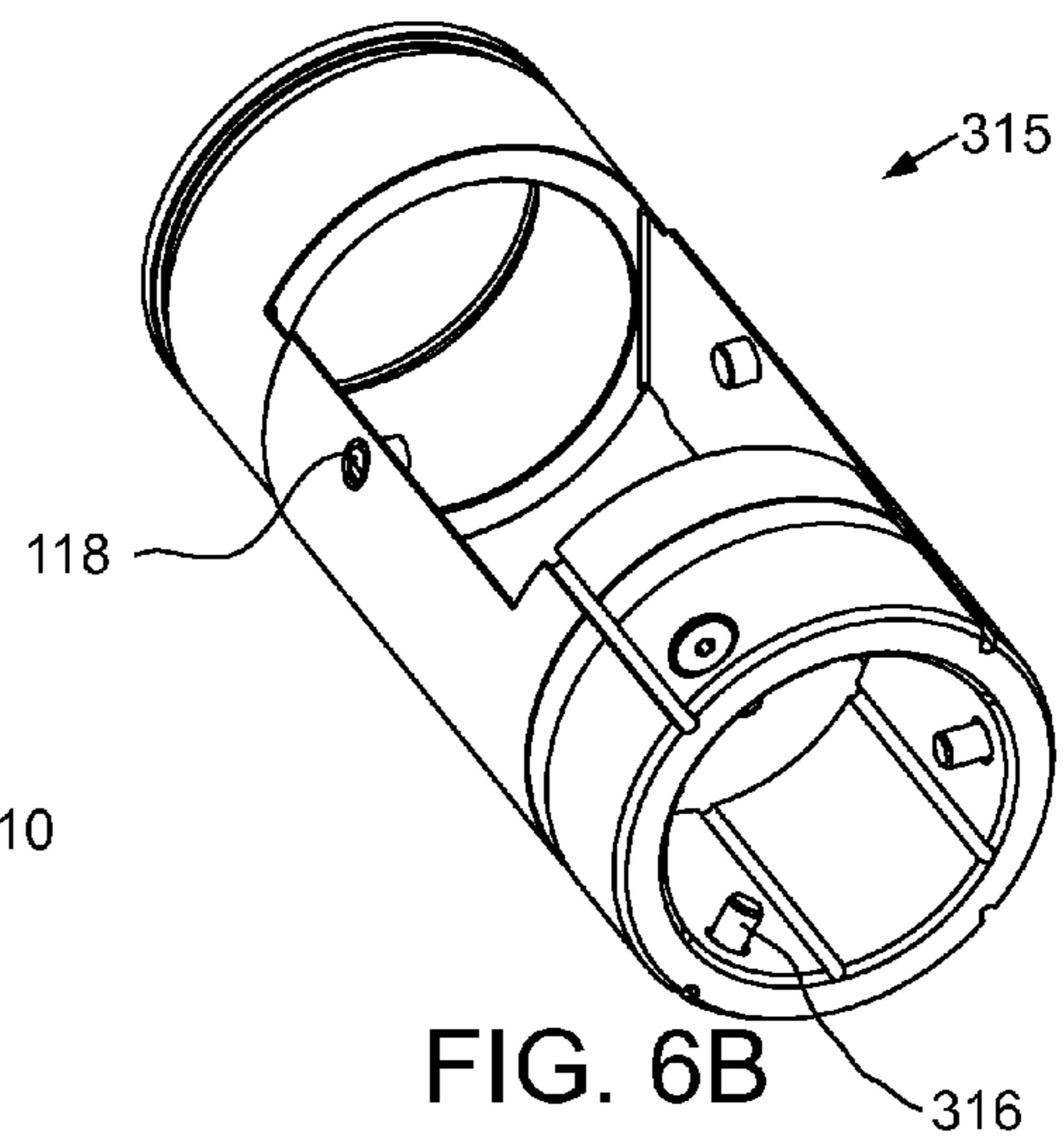


FIG. 6B

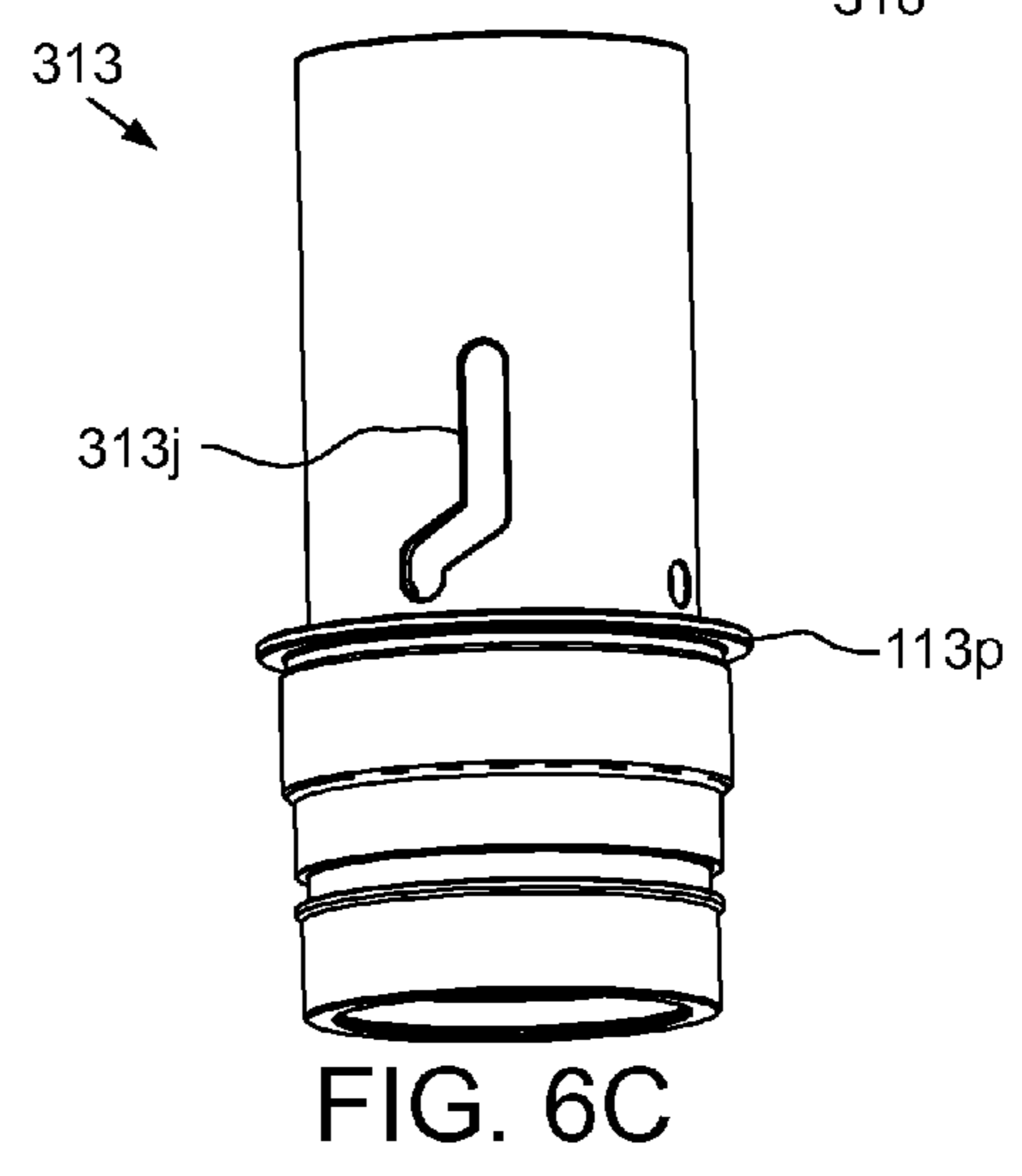


FIG. 6C

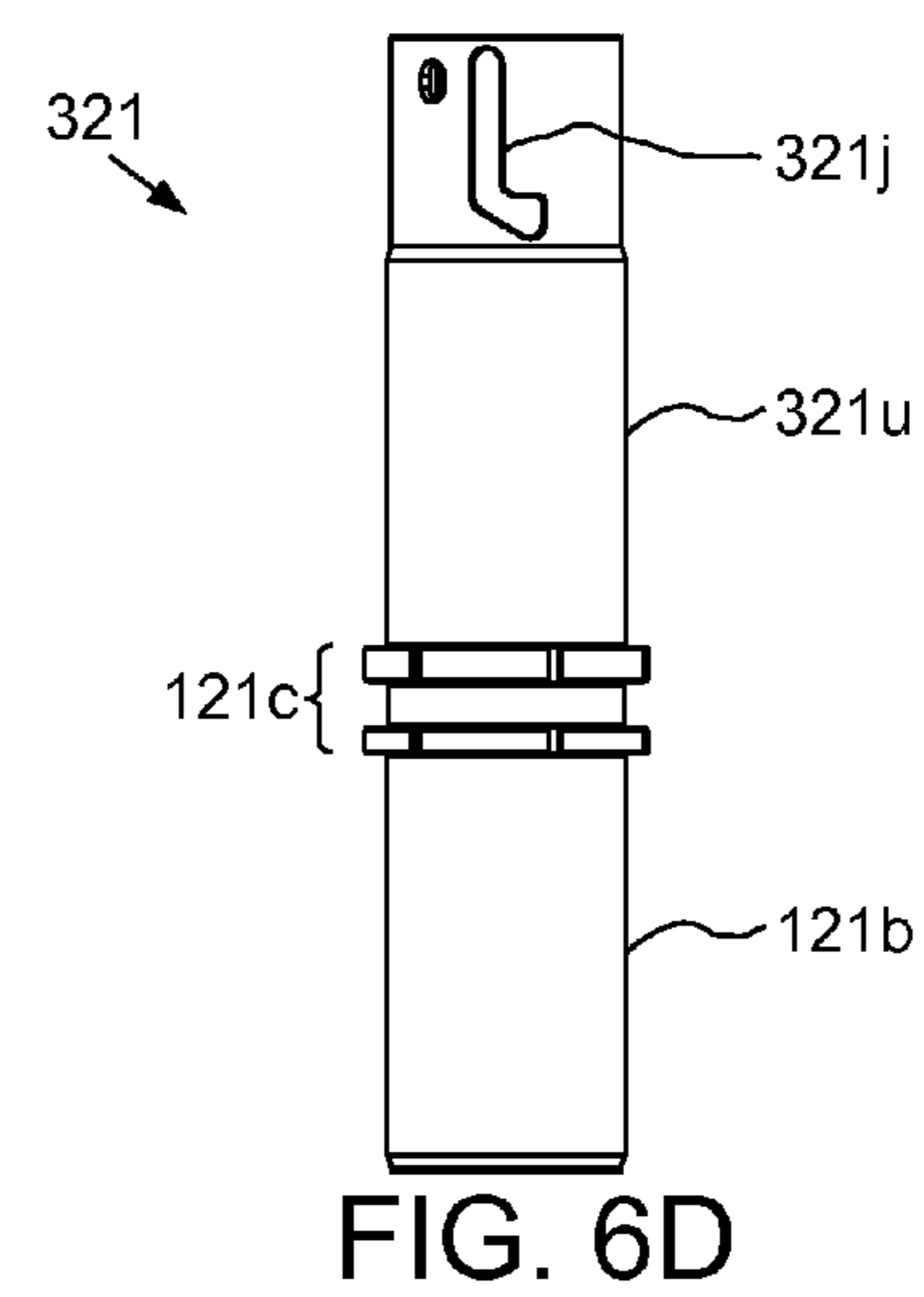
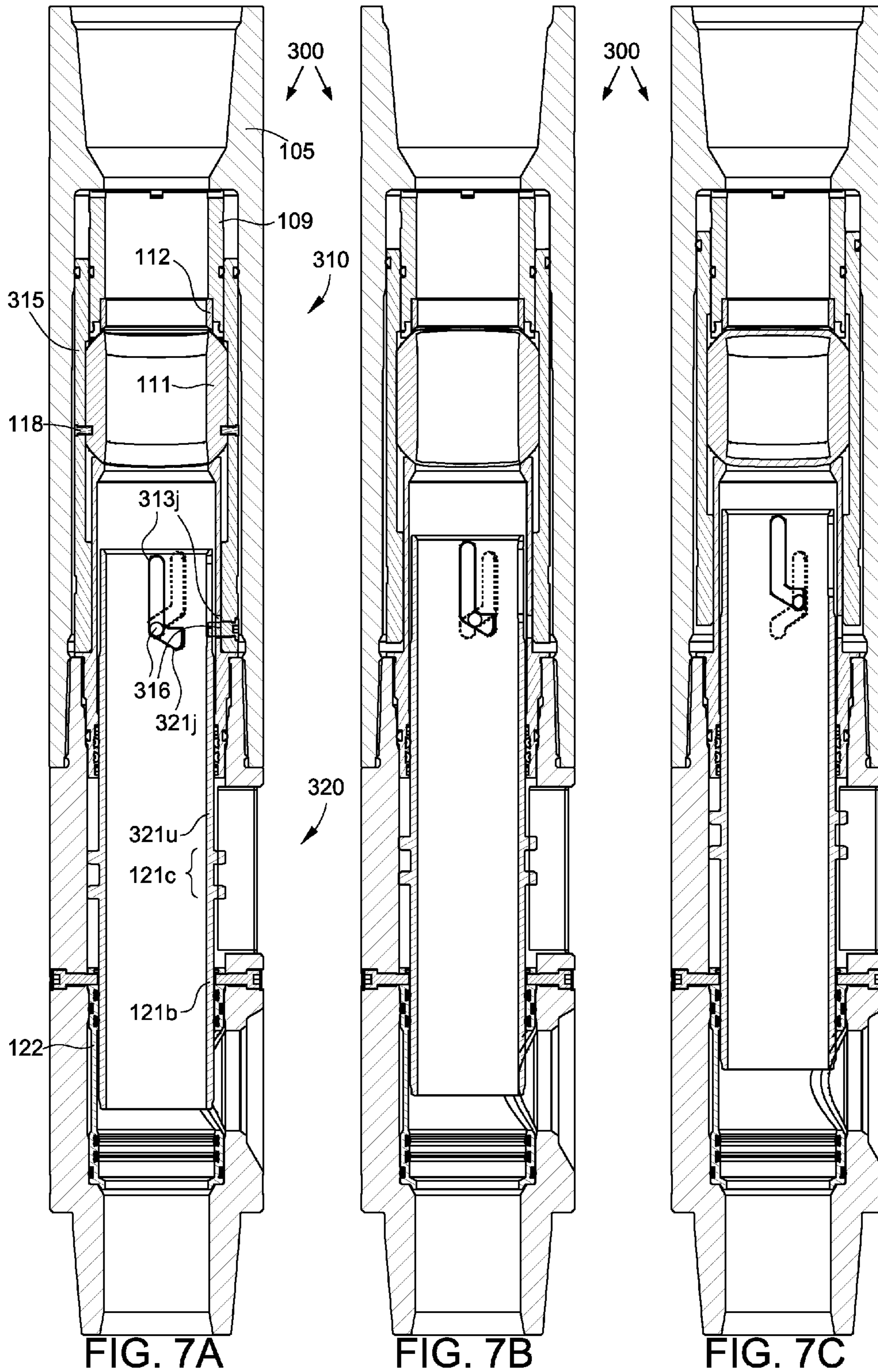
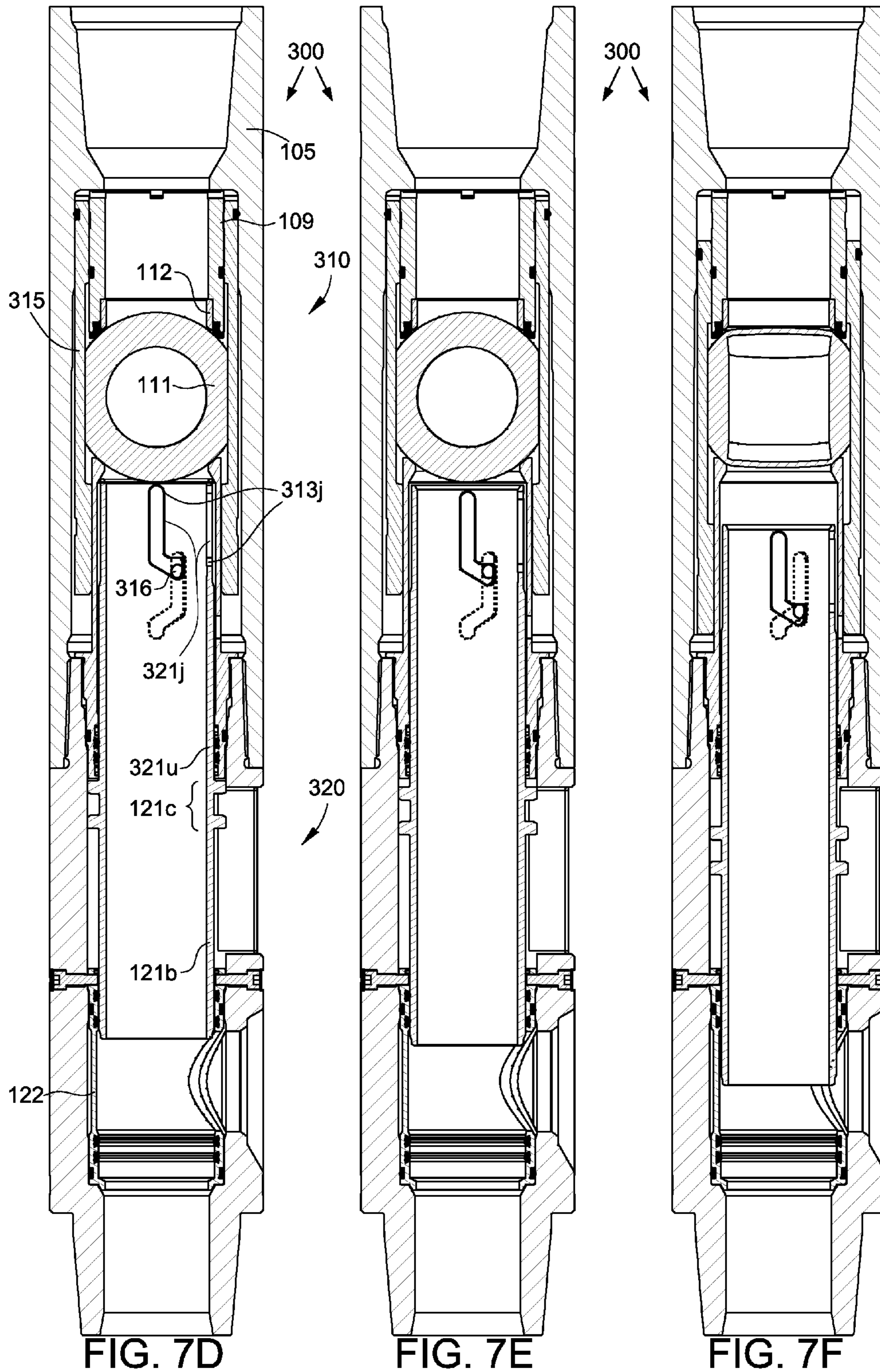
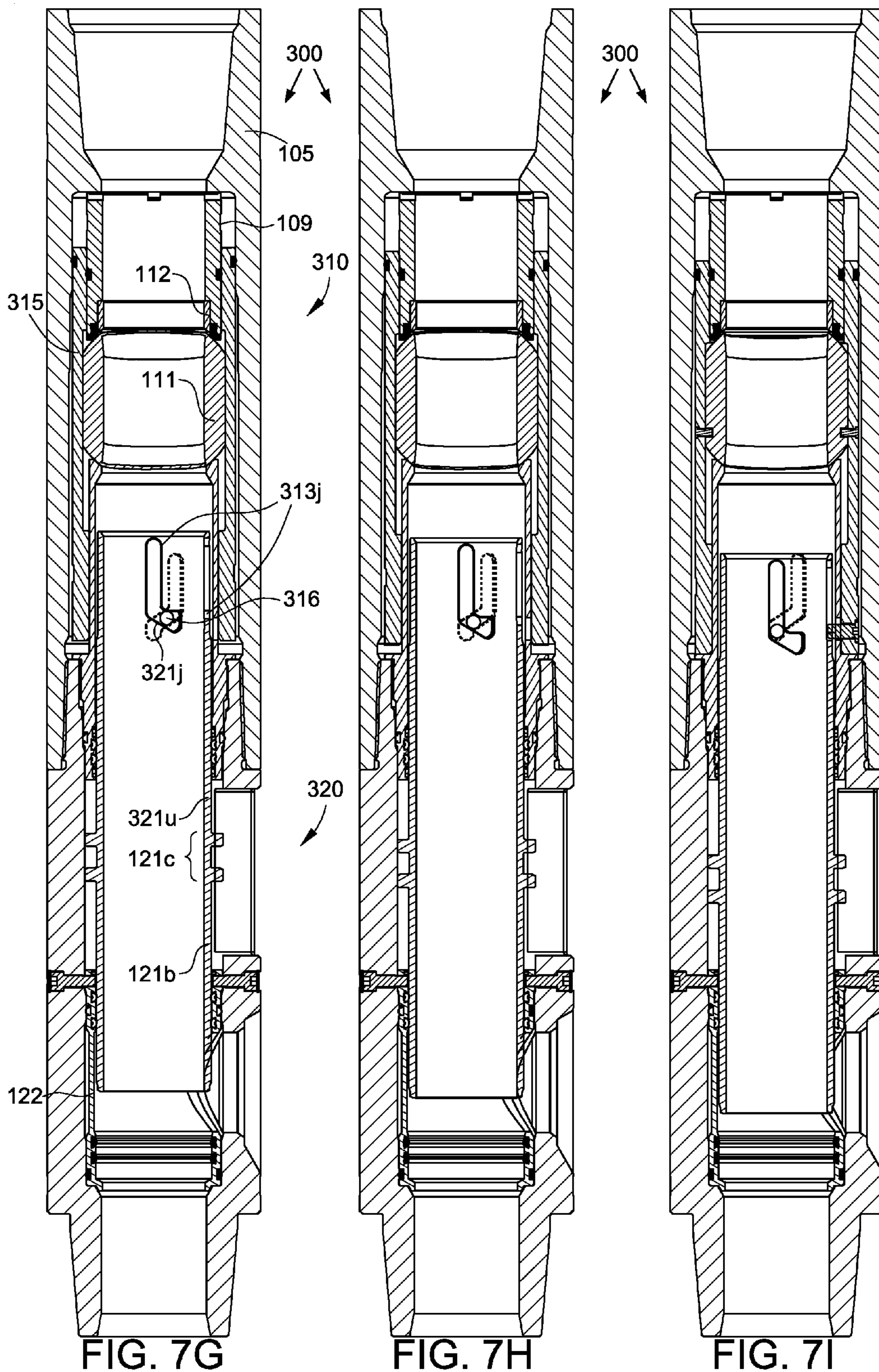
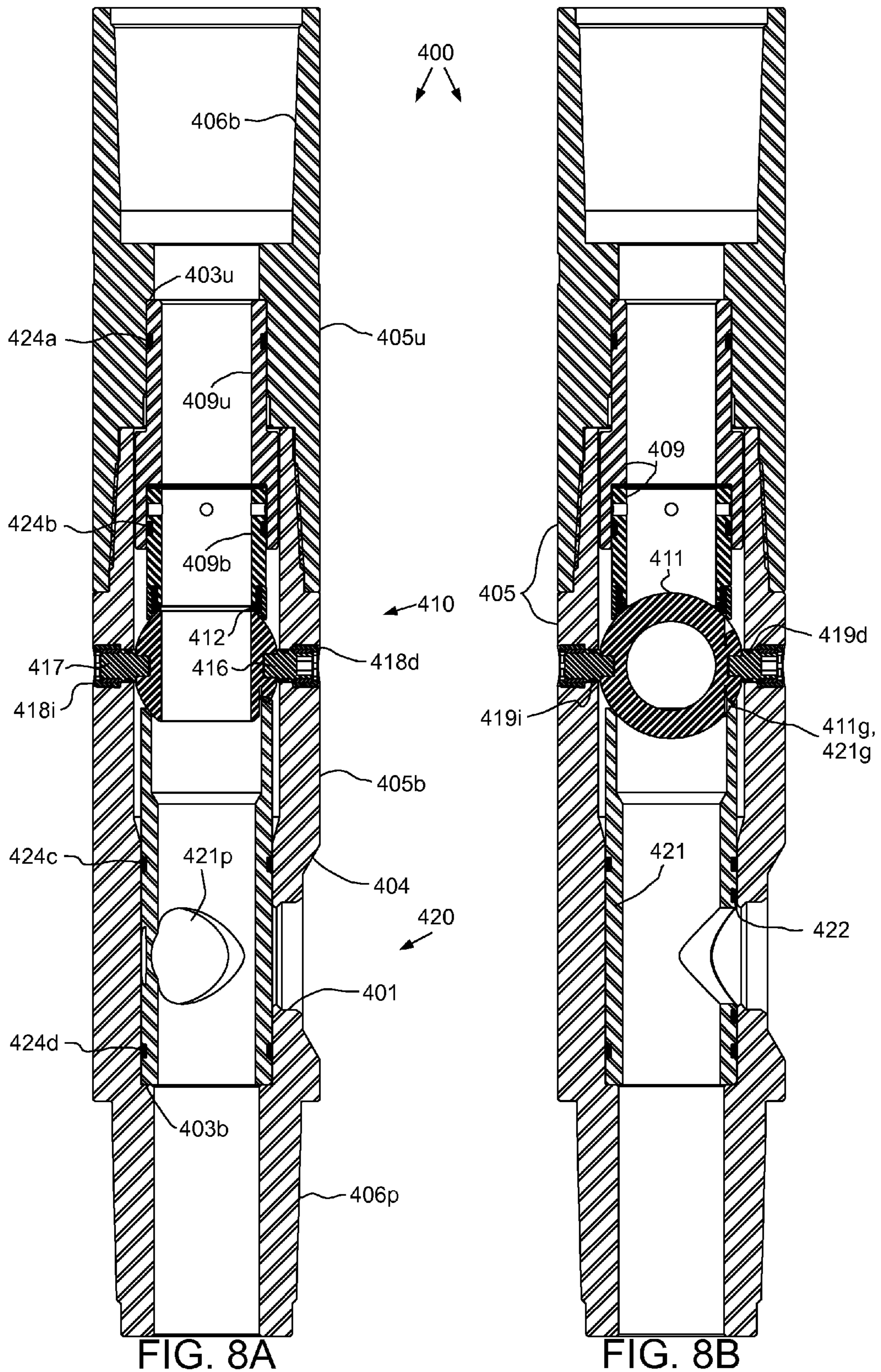


FIG. 6D









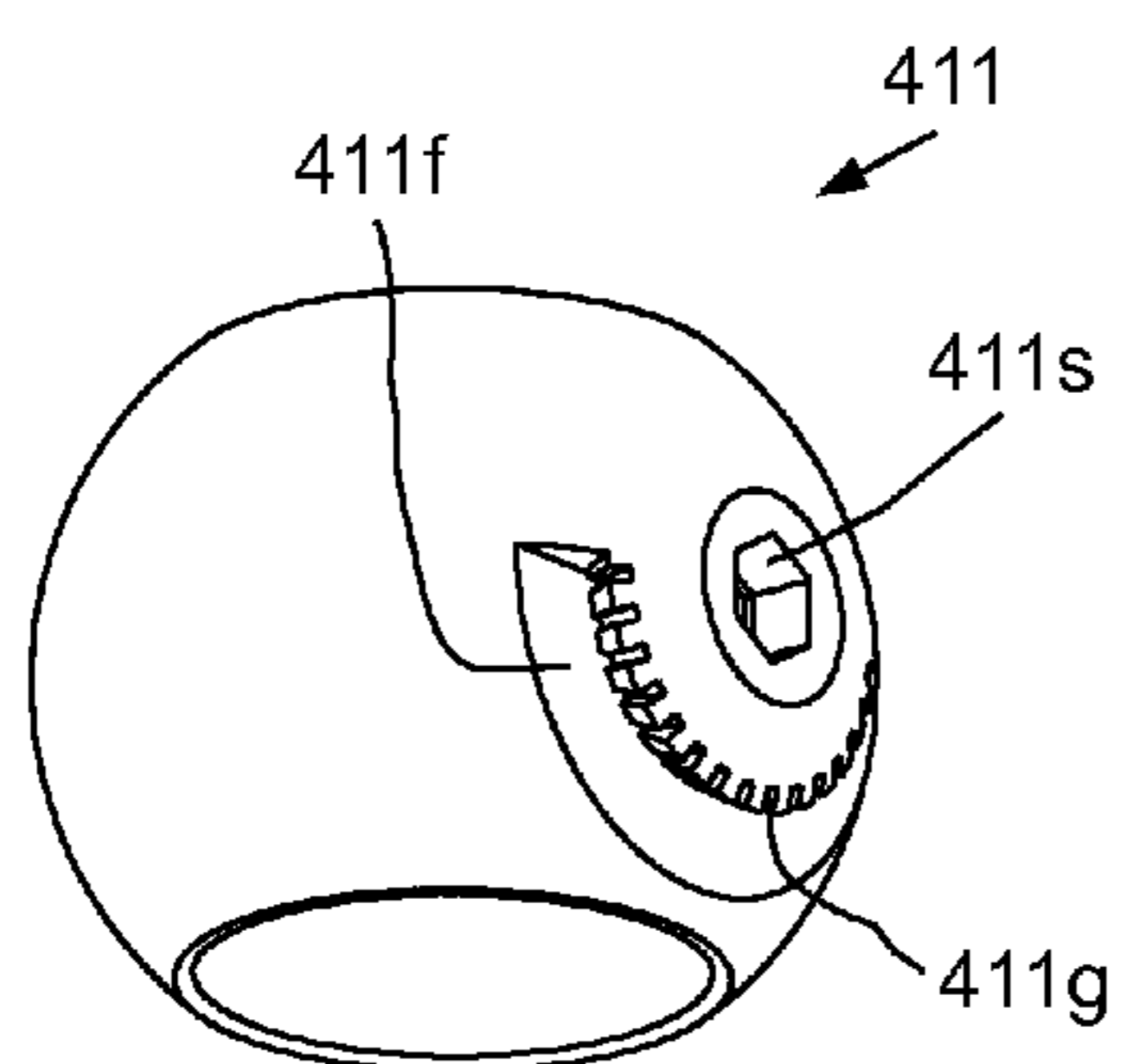


FIG. 8C

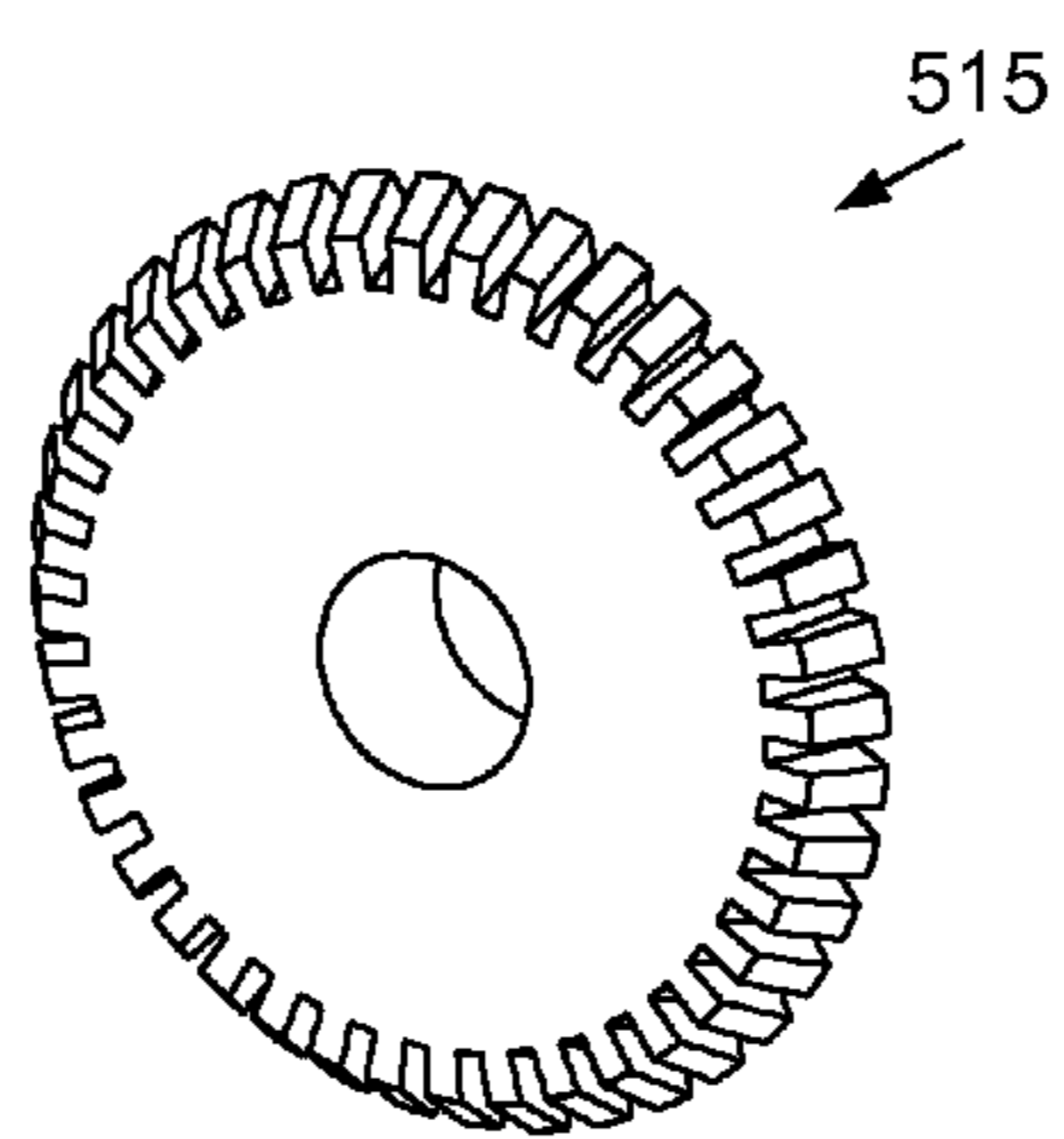


FIG. 9C

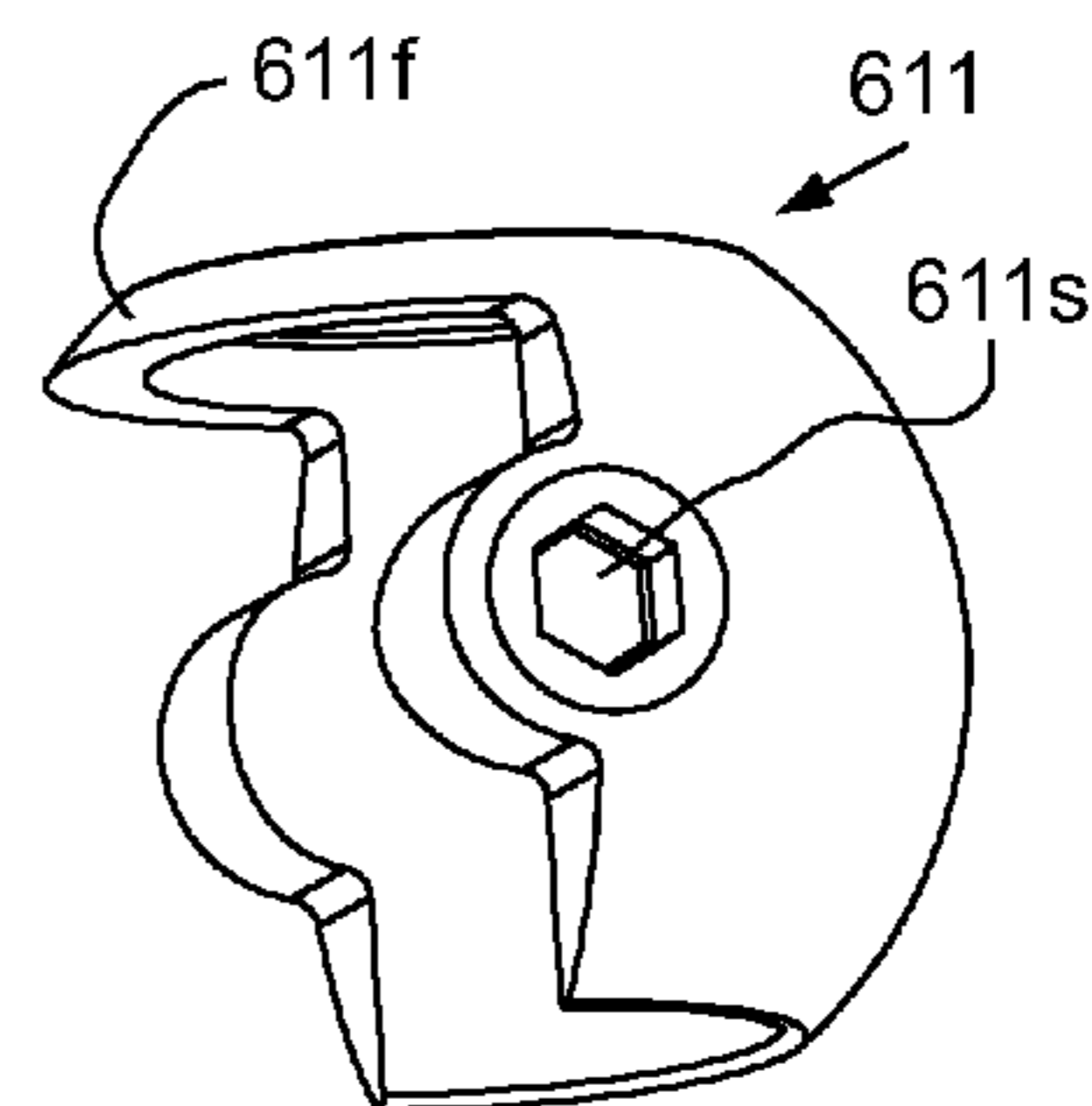


FIG. 10E

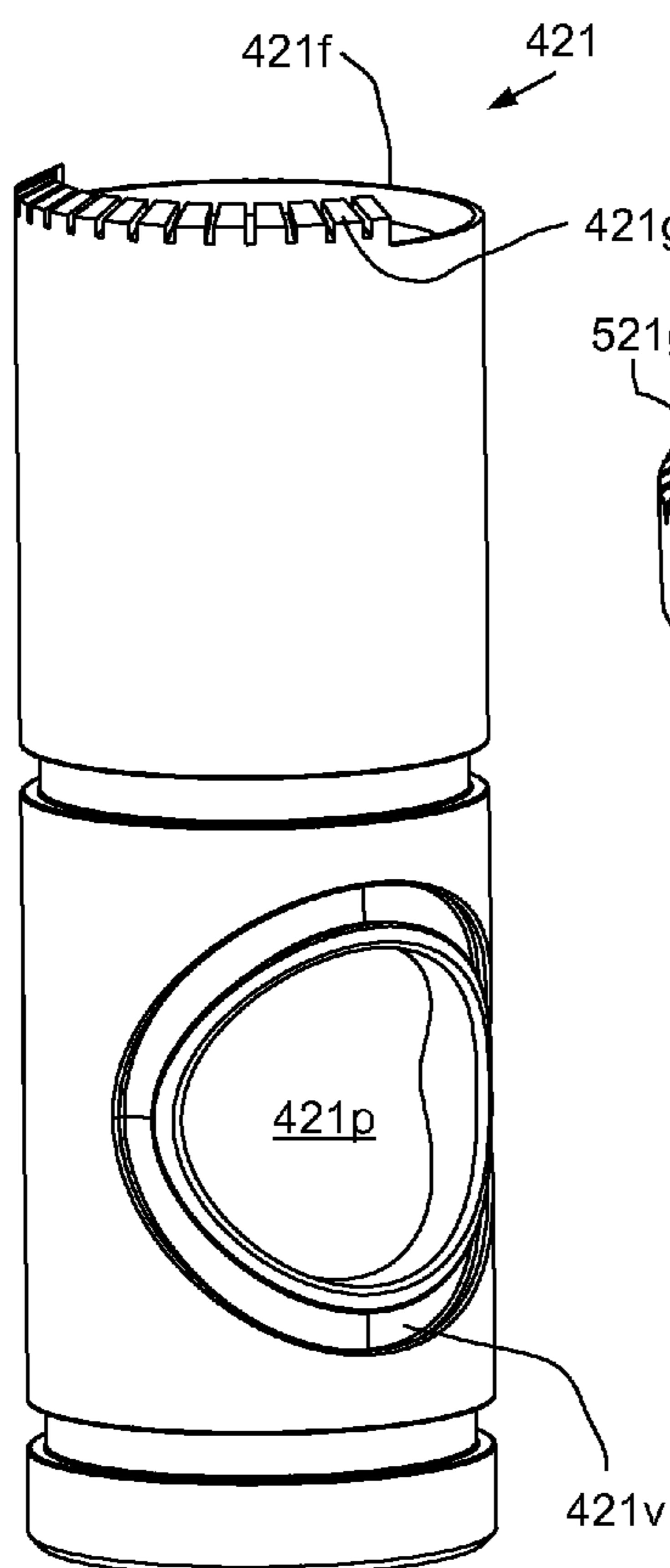


FIG. 8D

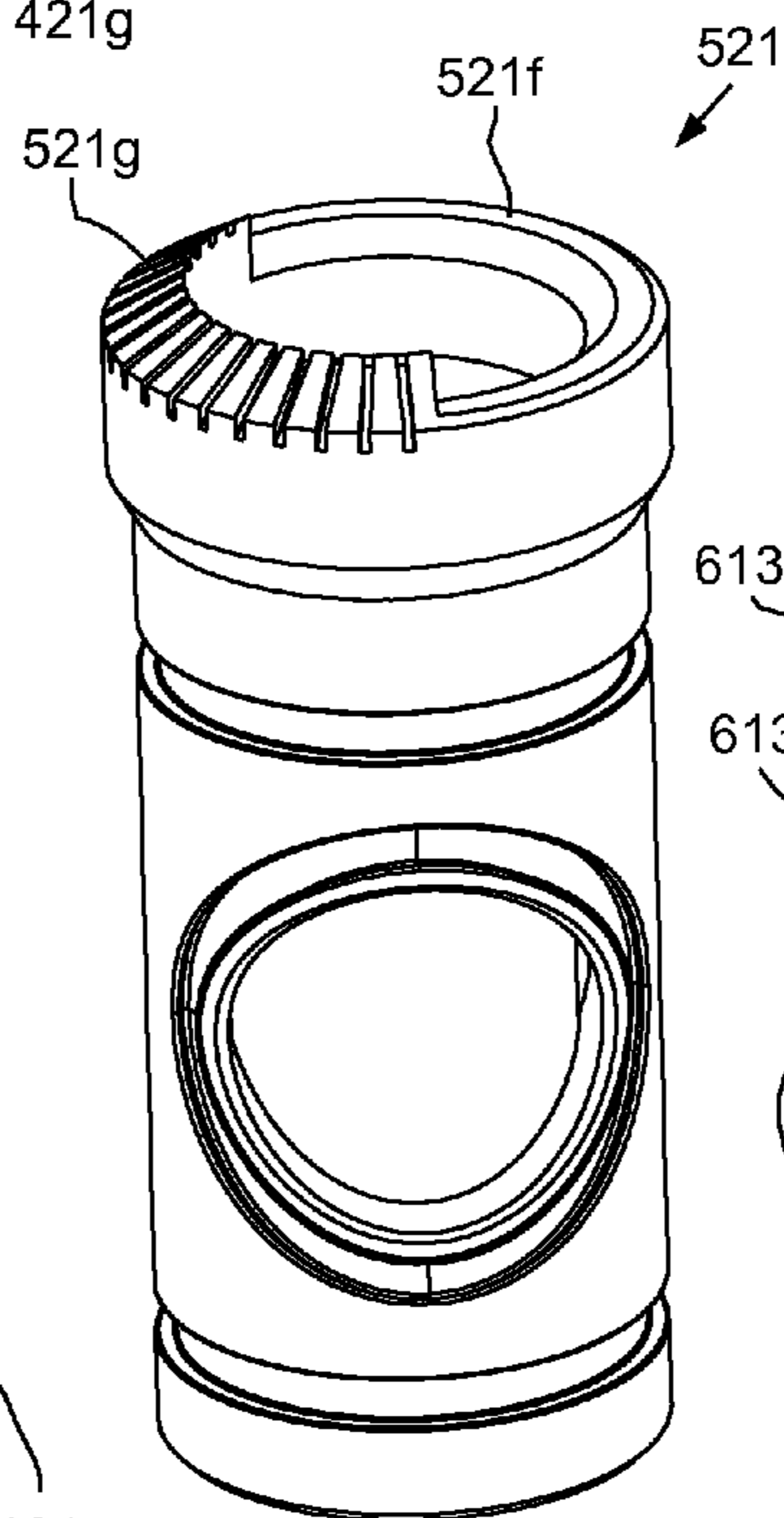


FIG. 9D

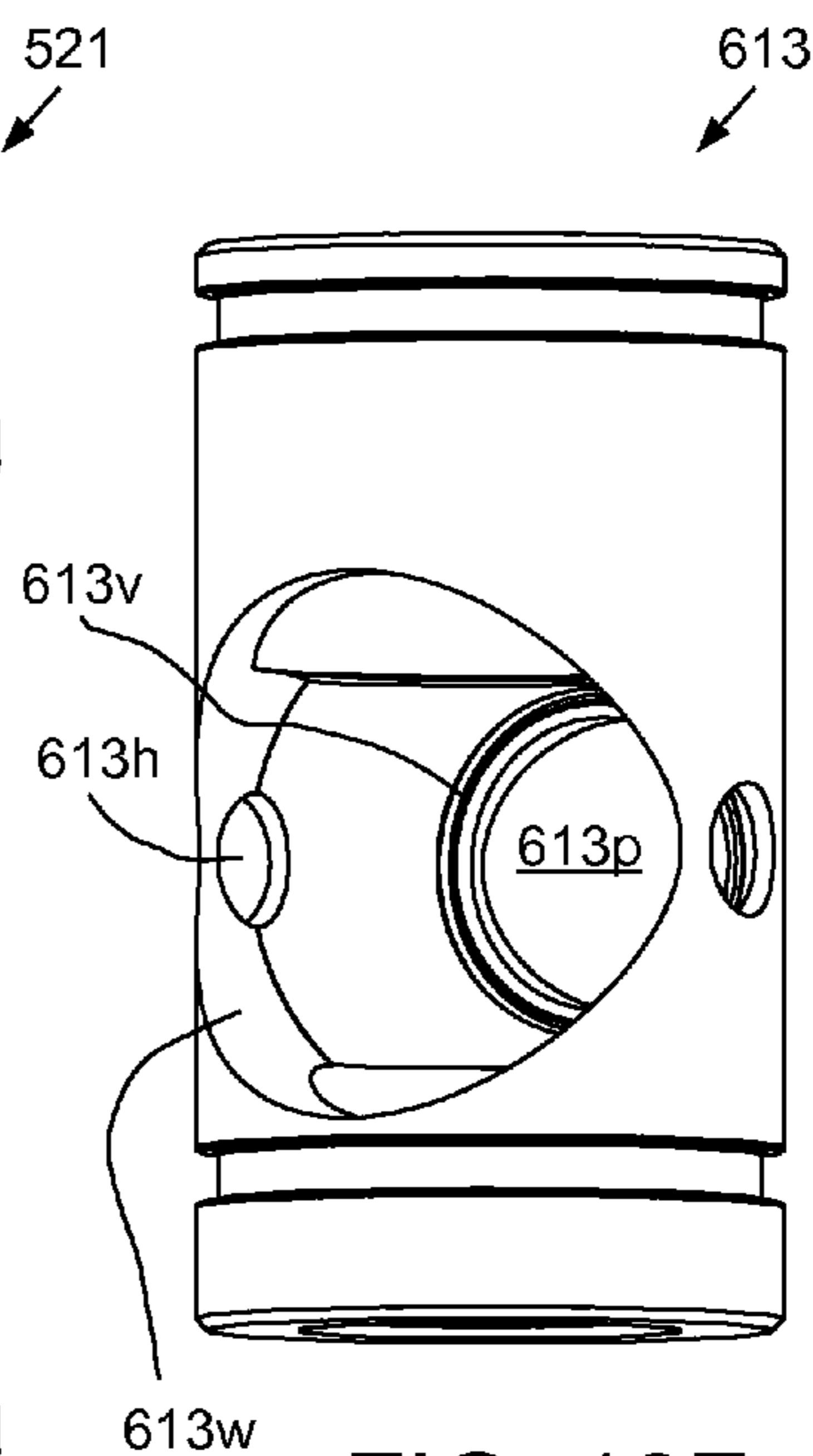
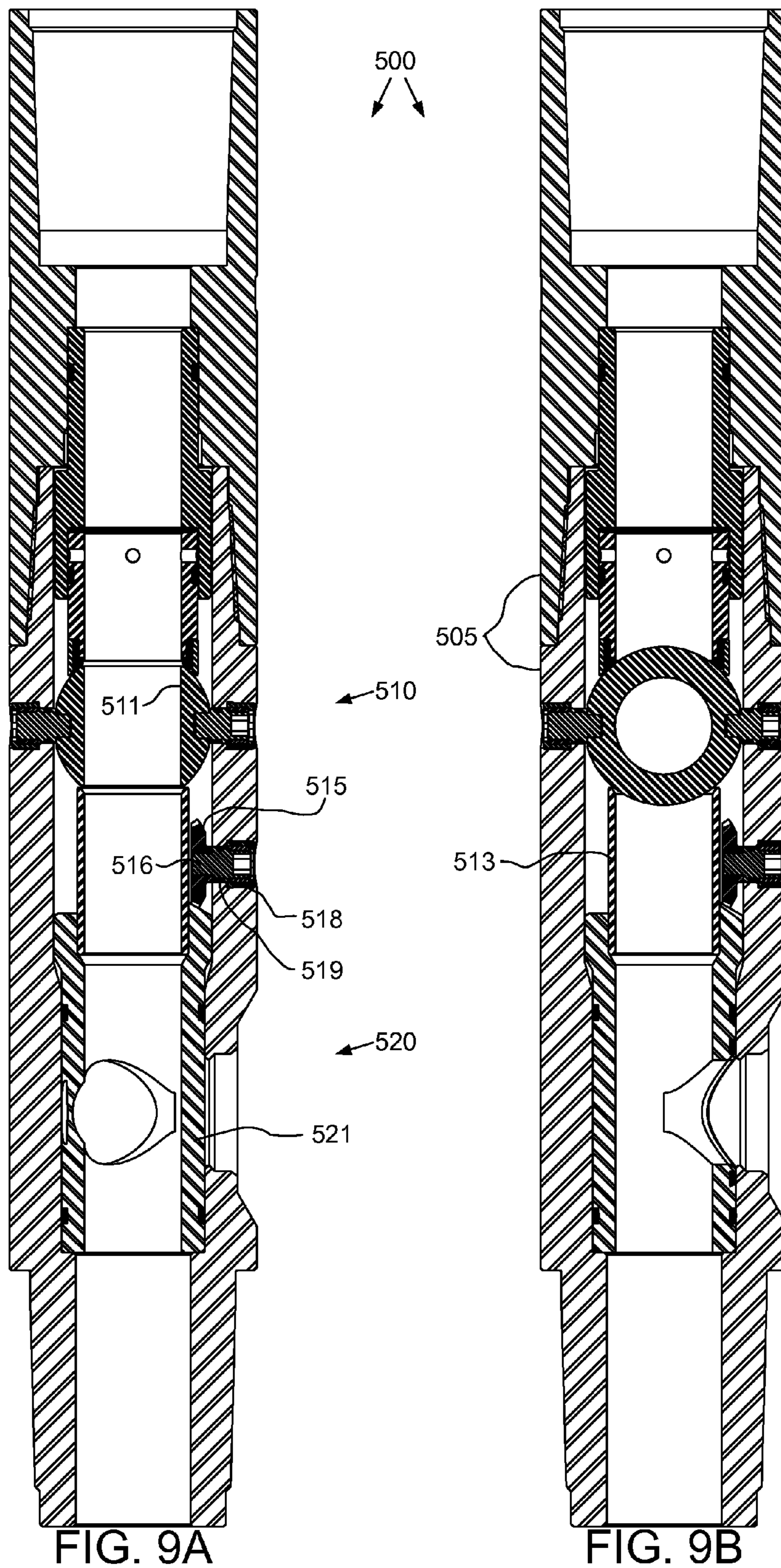
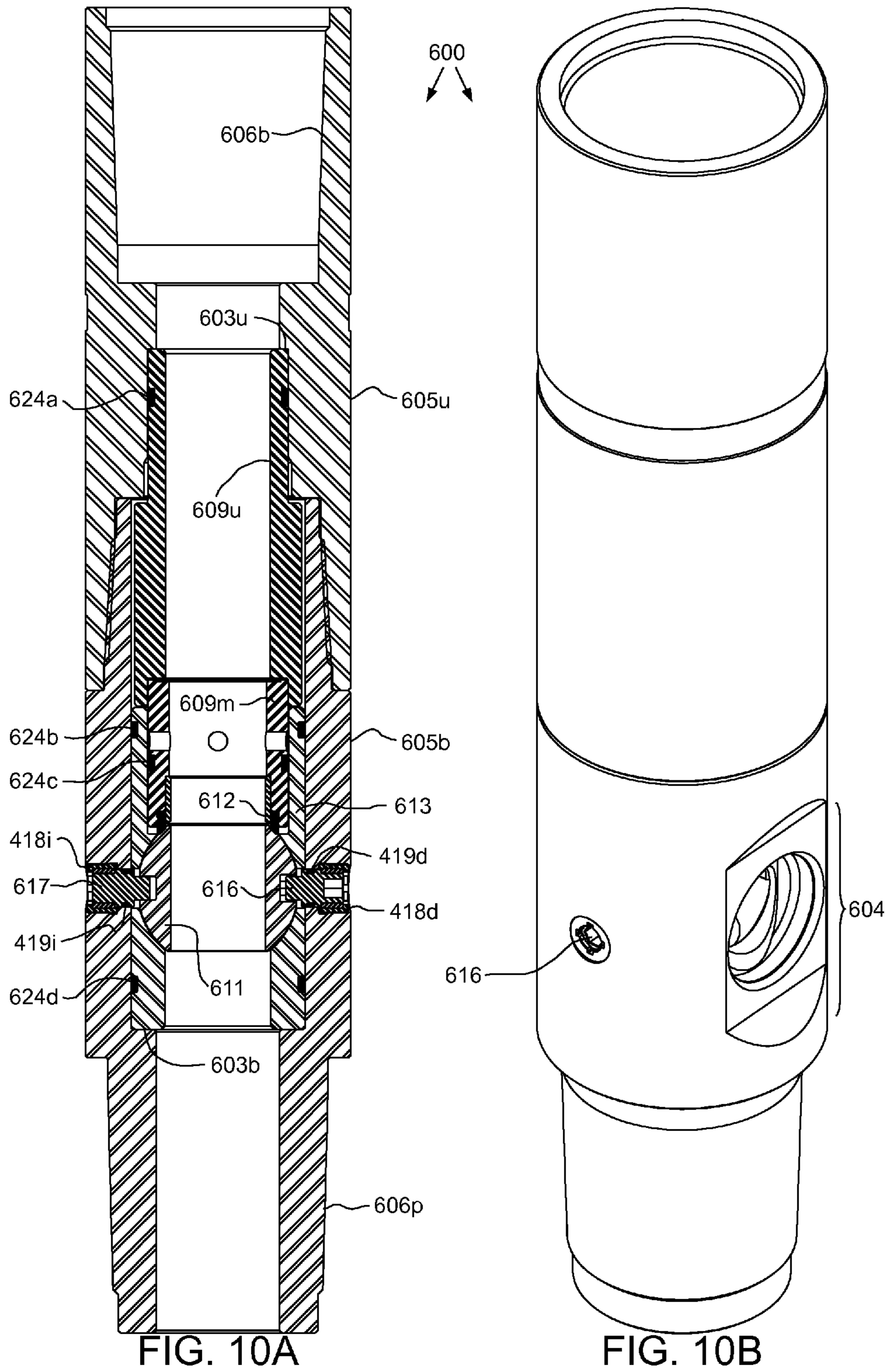
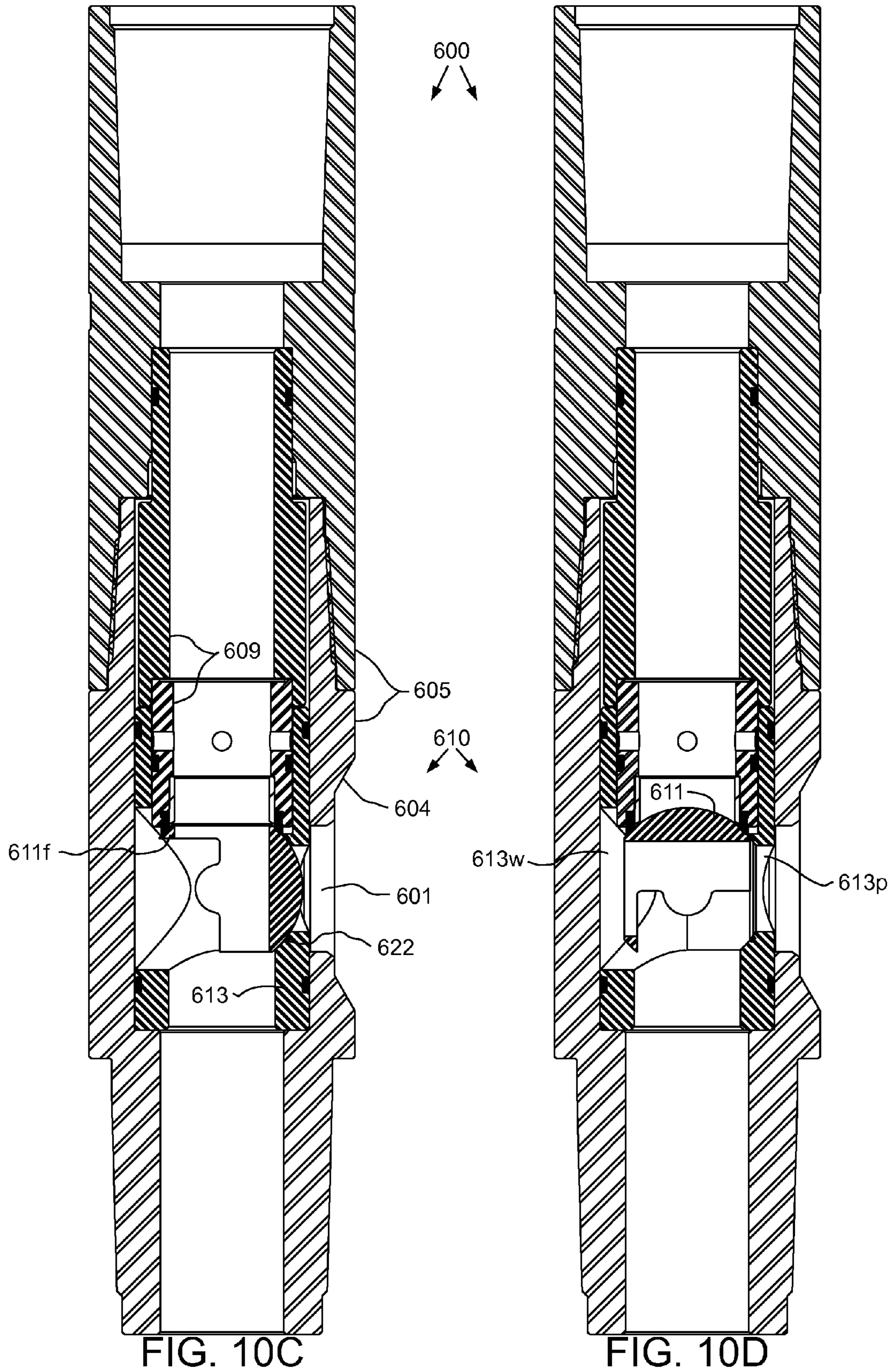


FIG. 10F







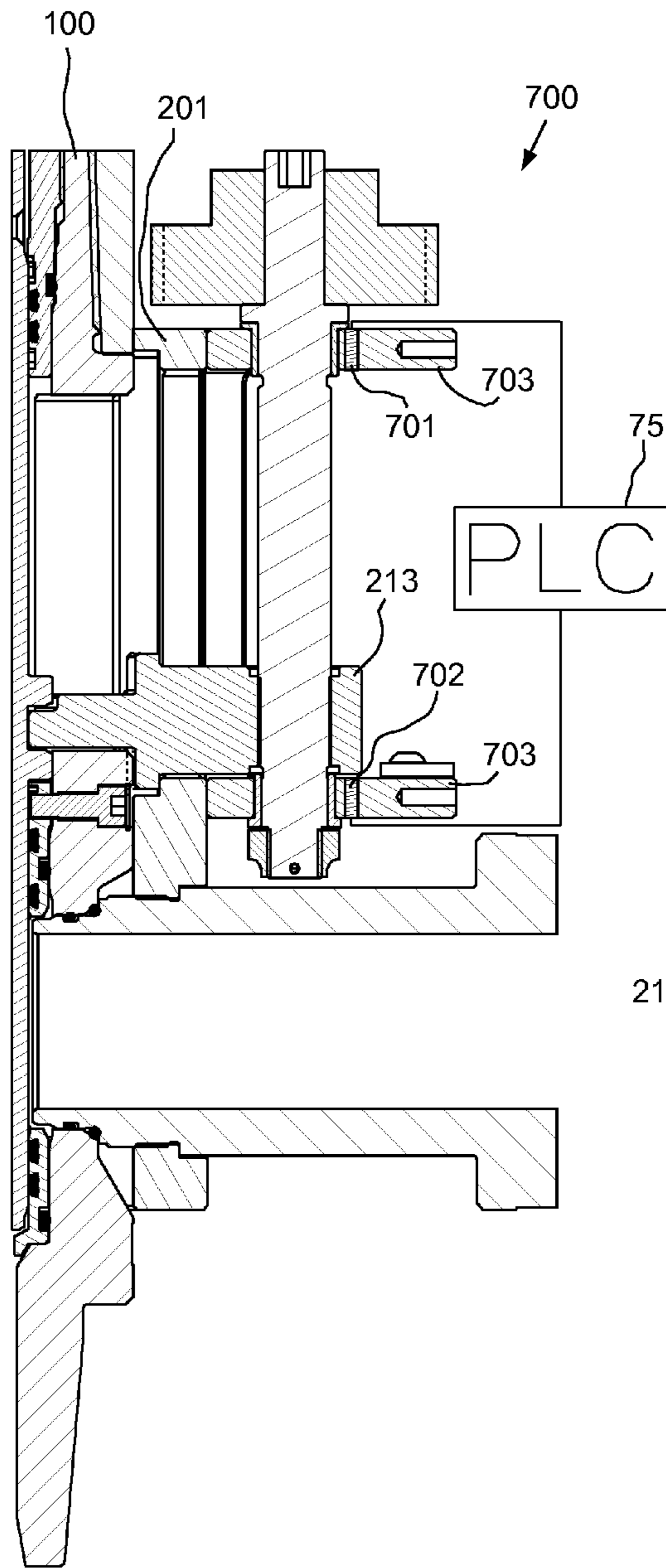


FIG. 11A

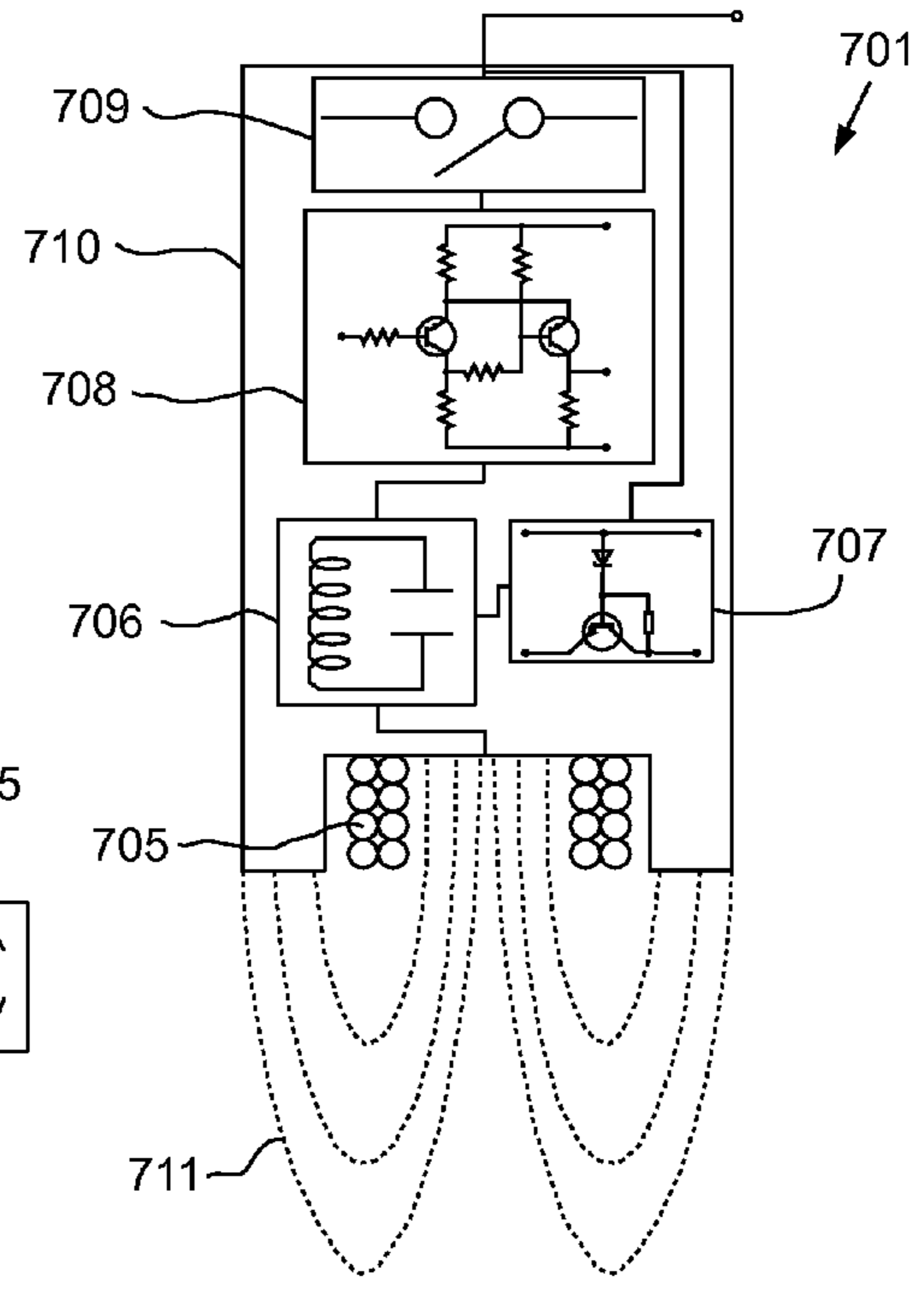


FIG. 11B

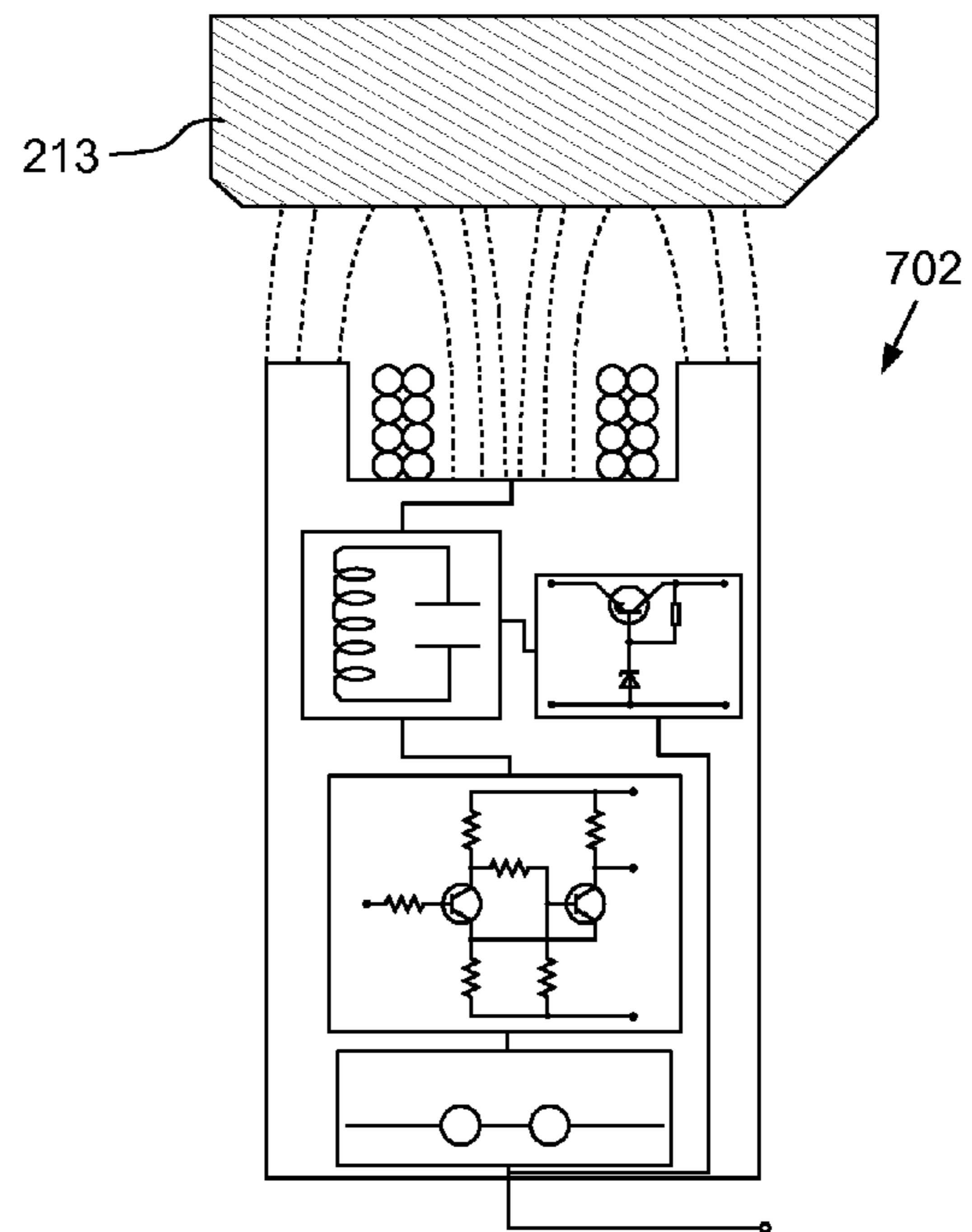


FIG. 11C

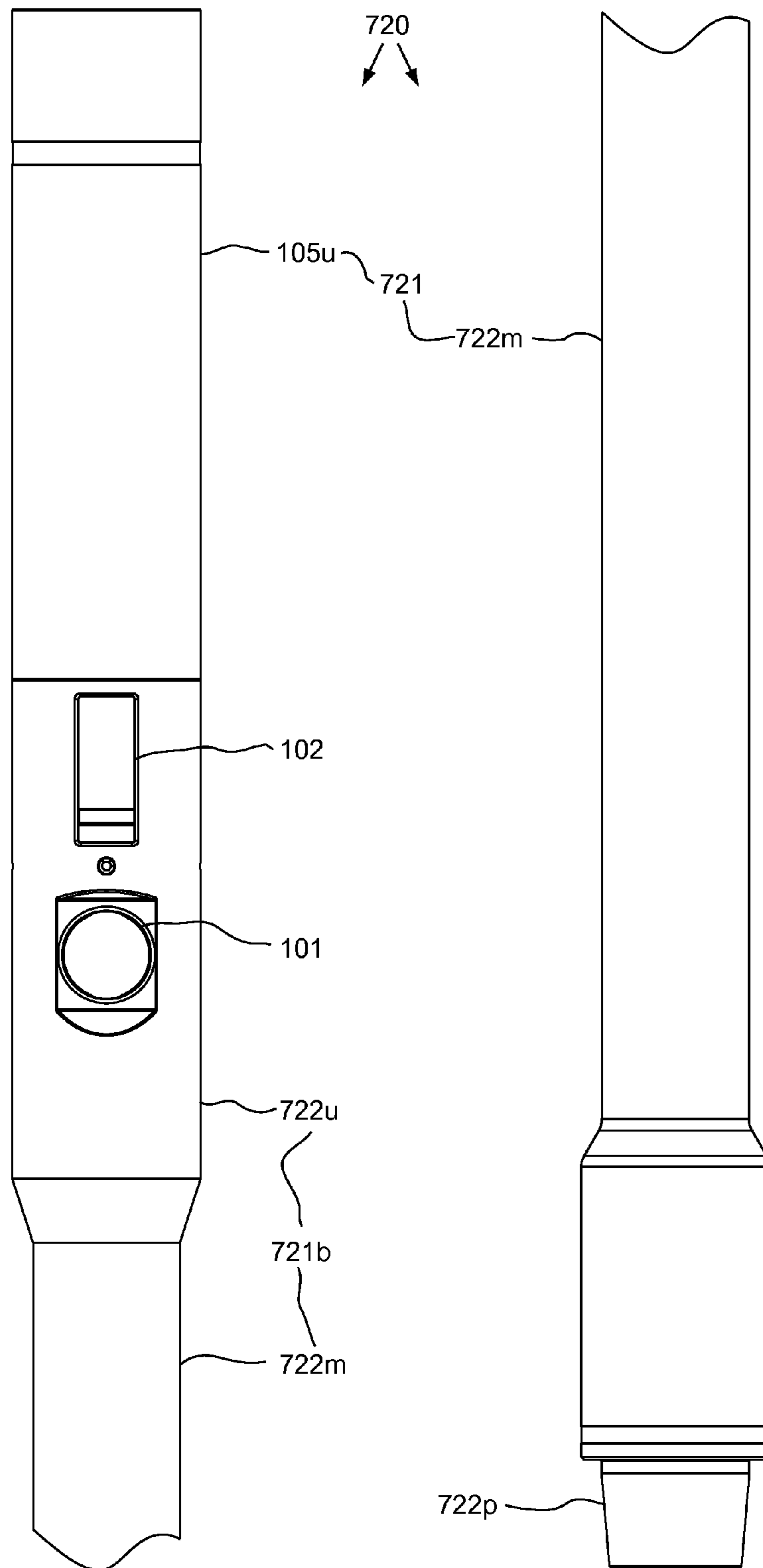


FIG. 12A

FIG. 12B

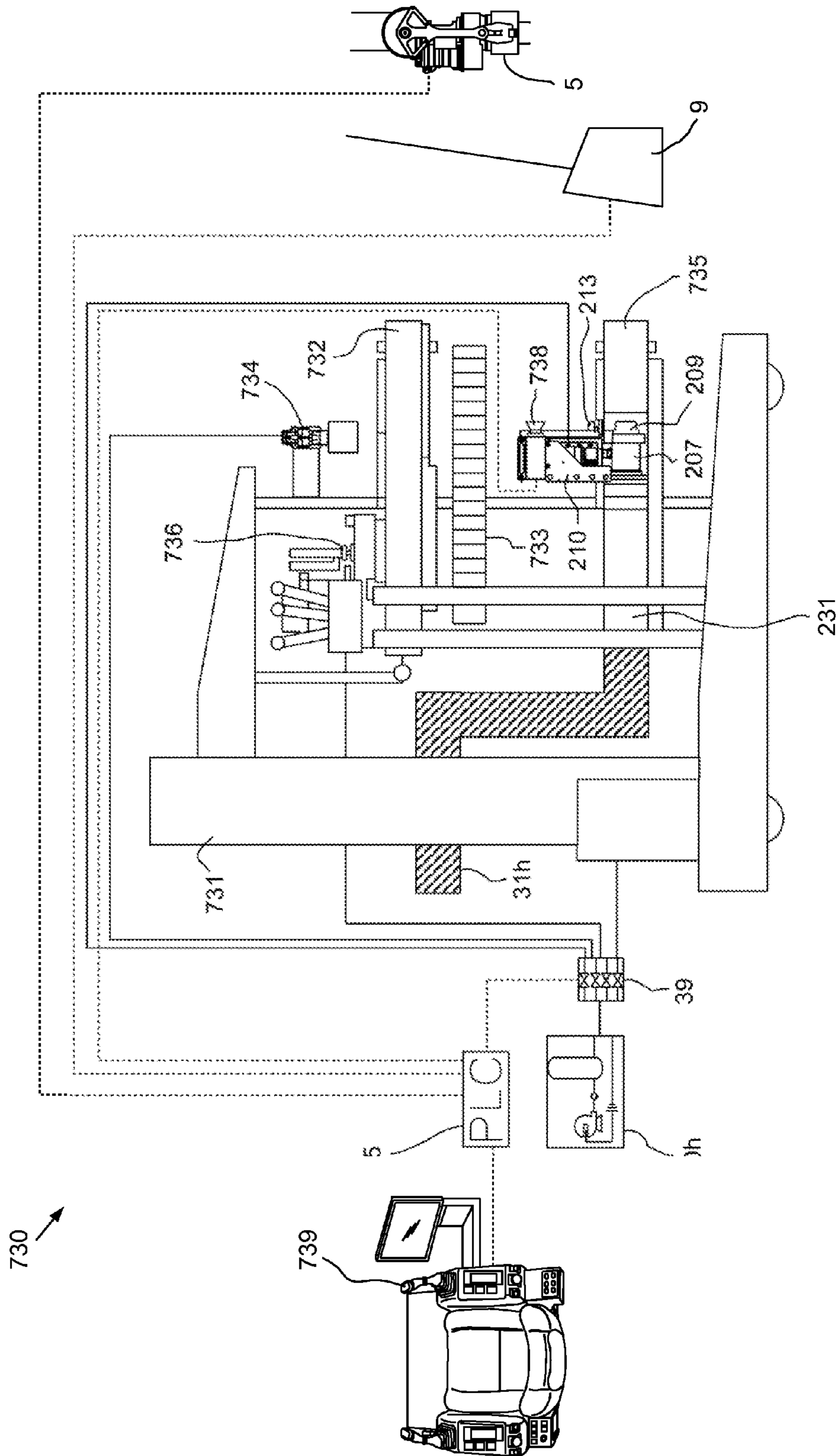


FIG. 13A

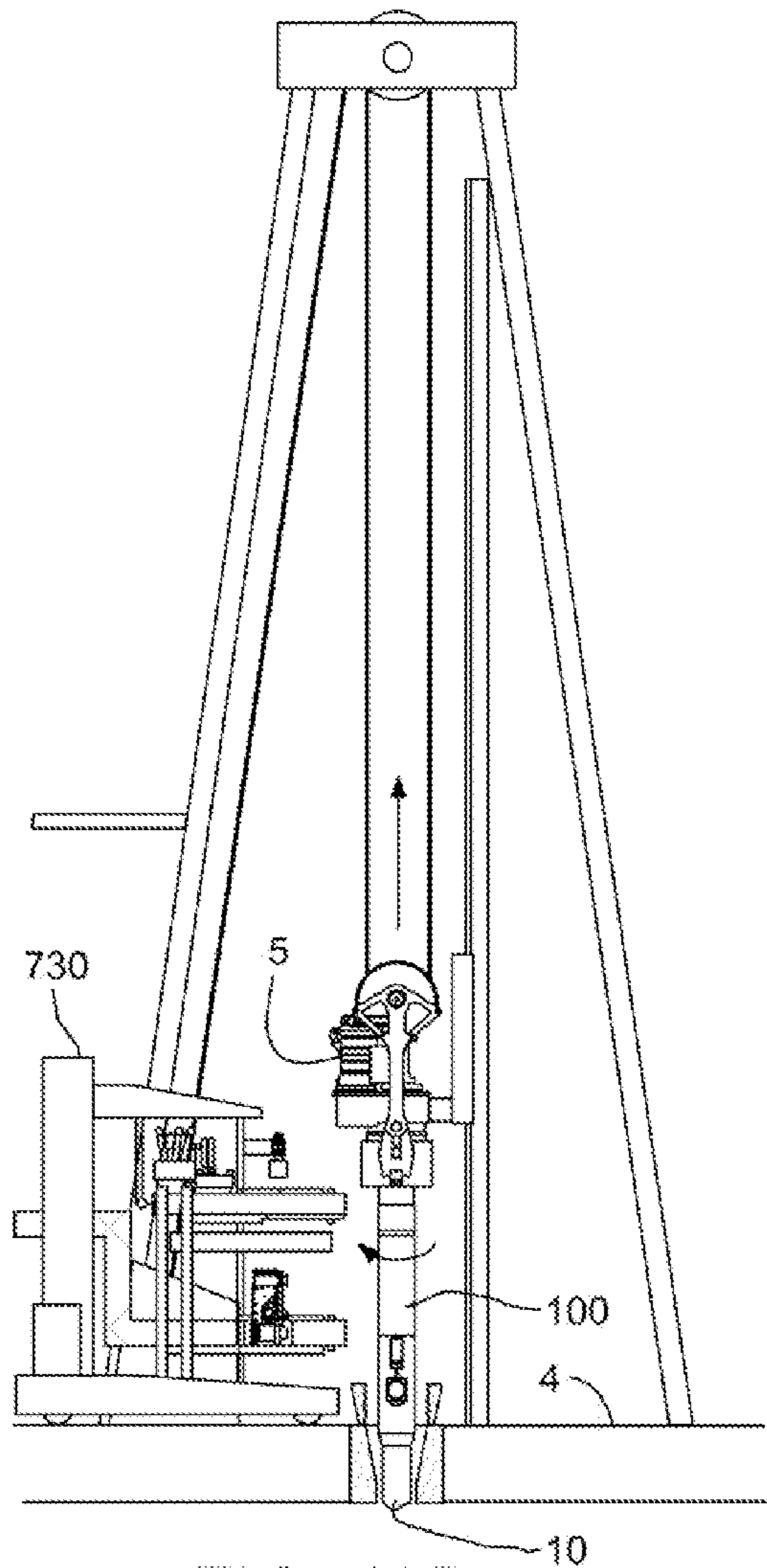


FIG. 13B

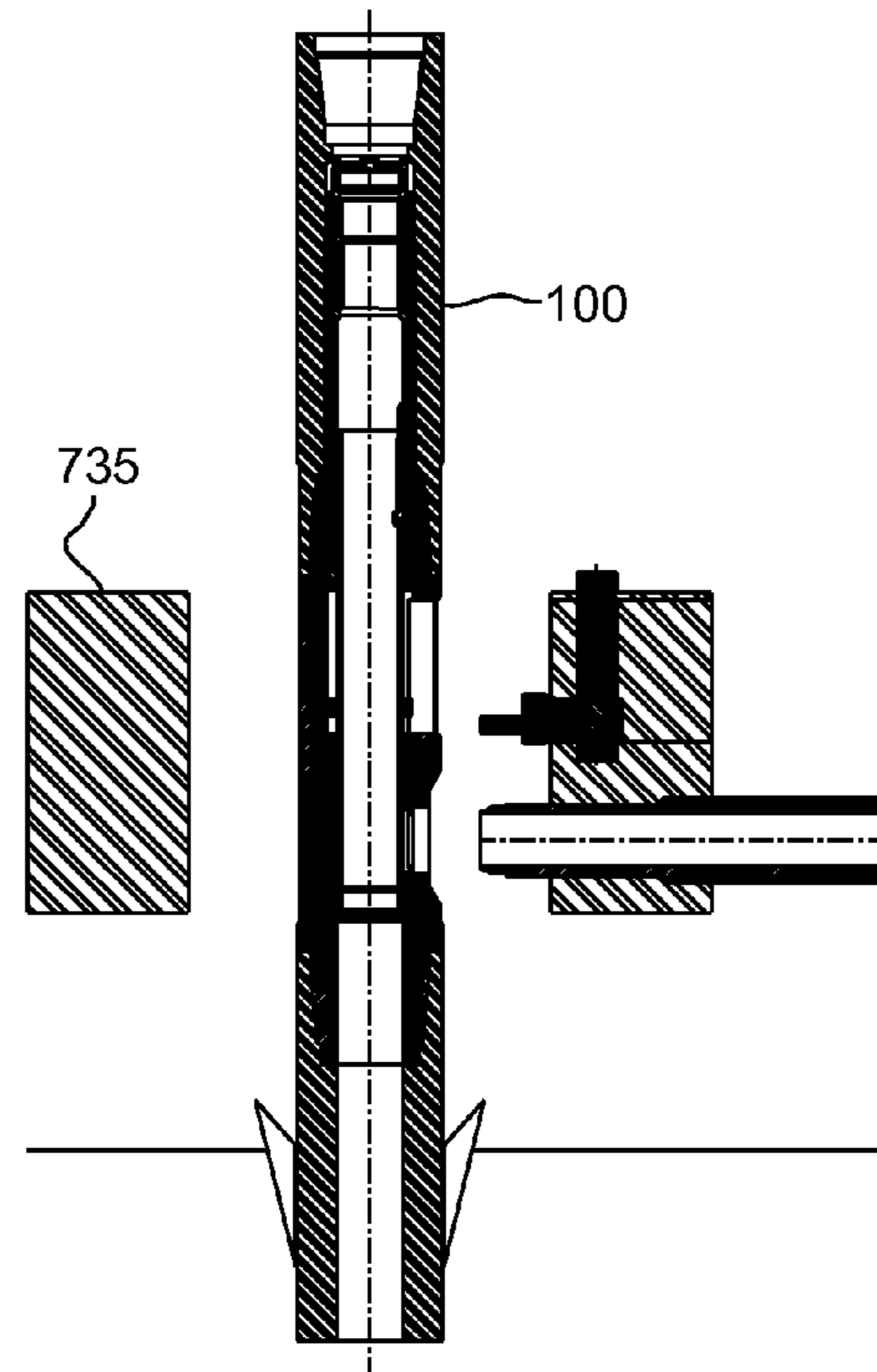


FIG. 13C

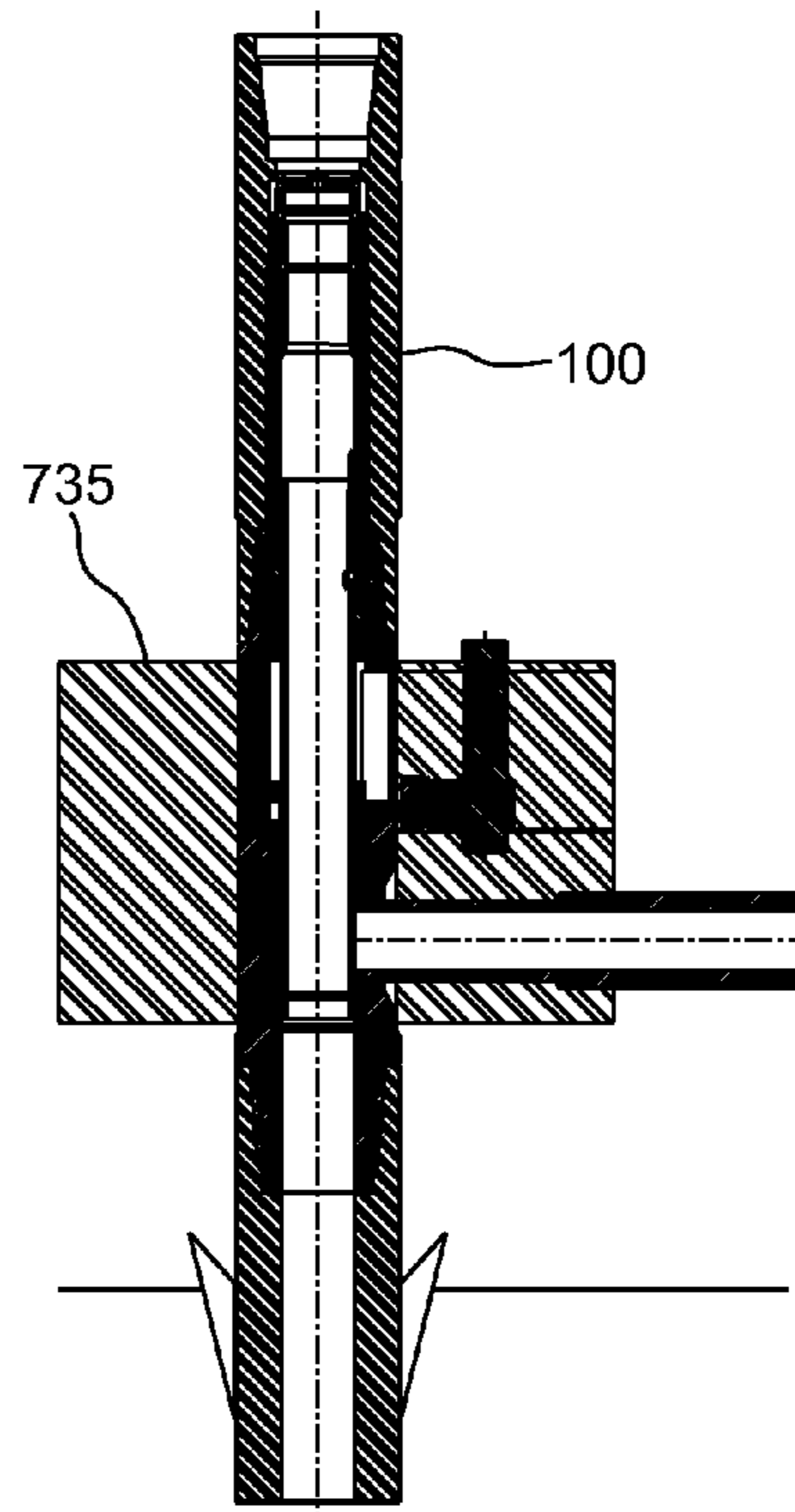


FIG. 13D

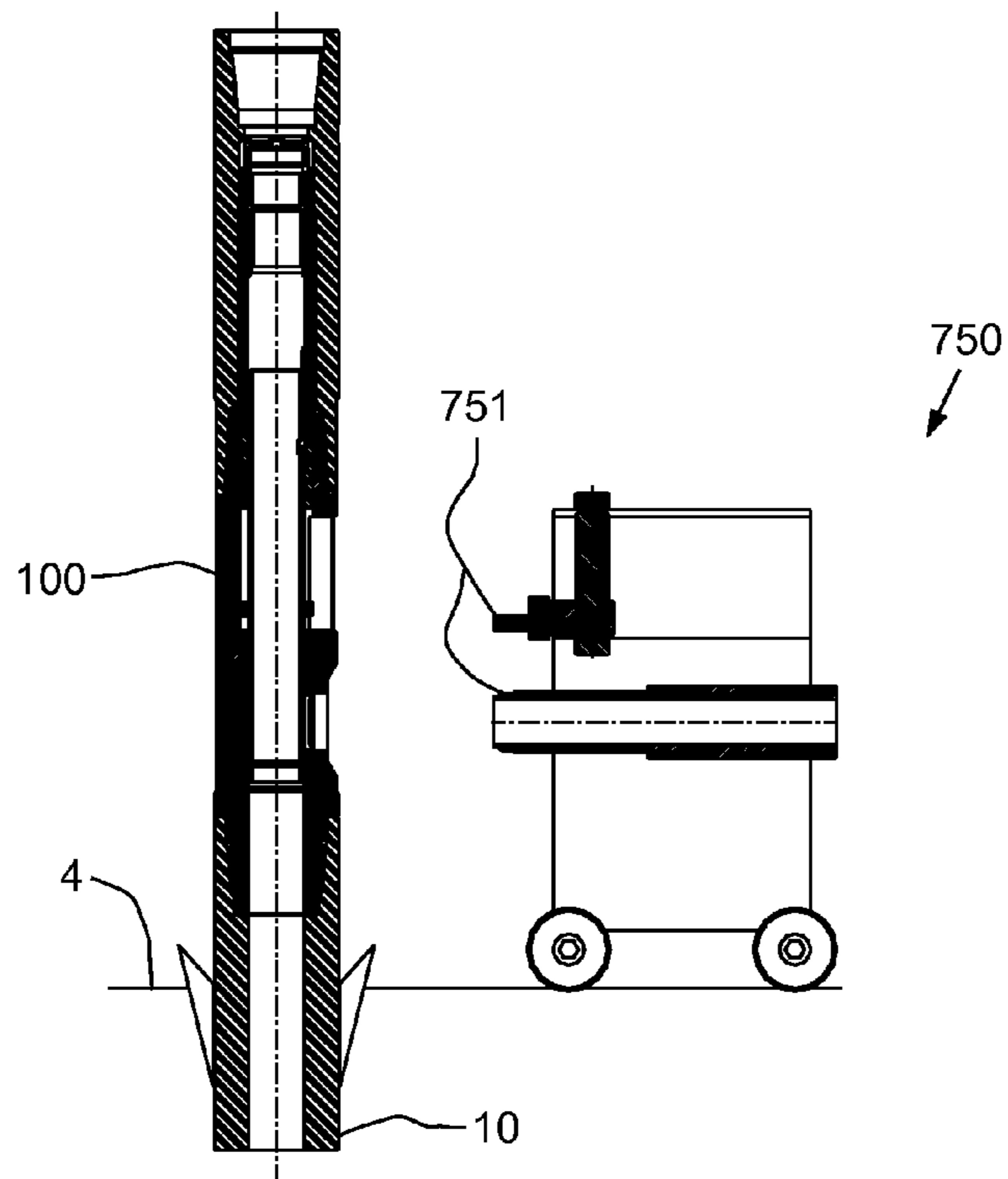


FIG. 14A

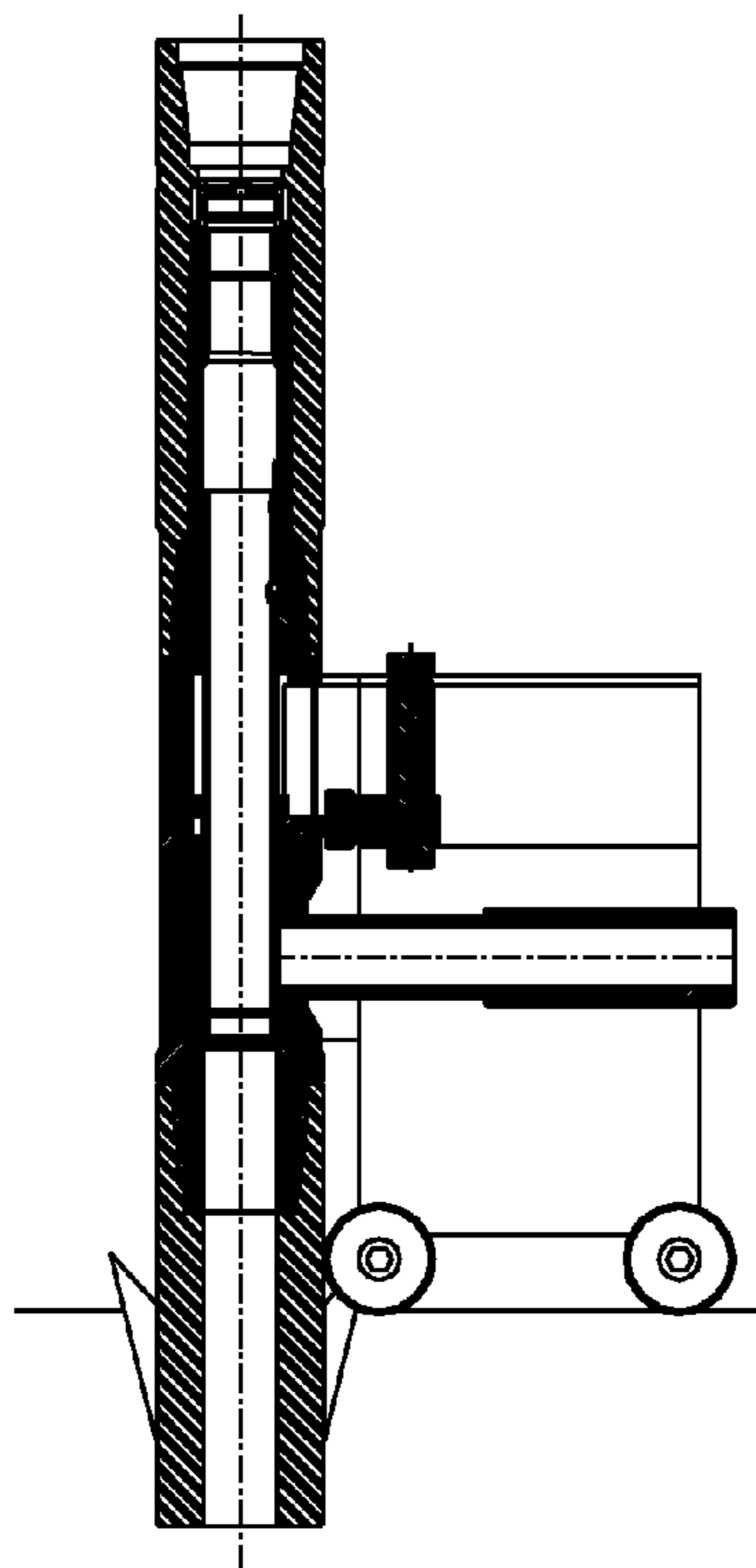


FIG. 14B

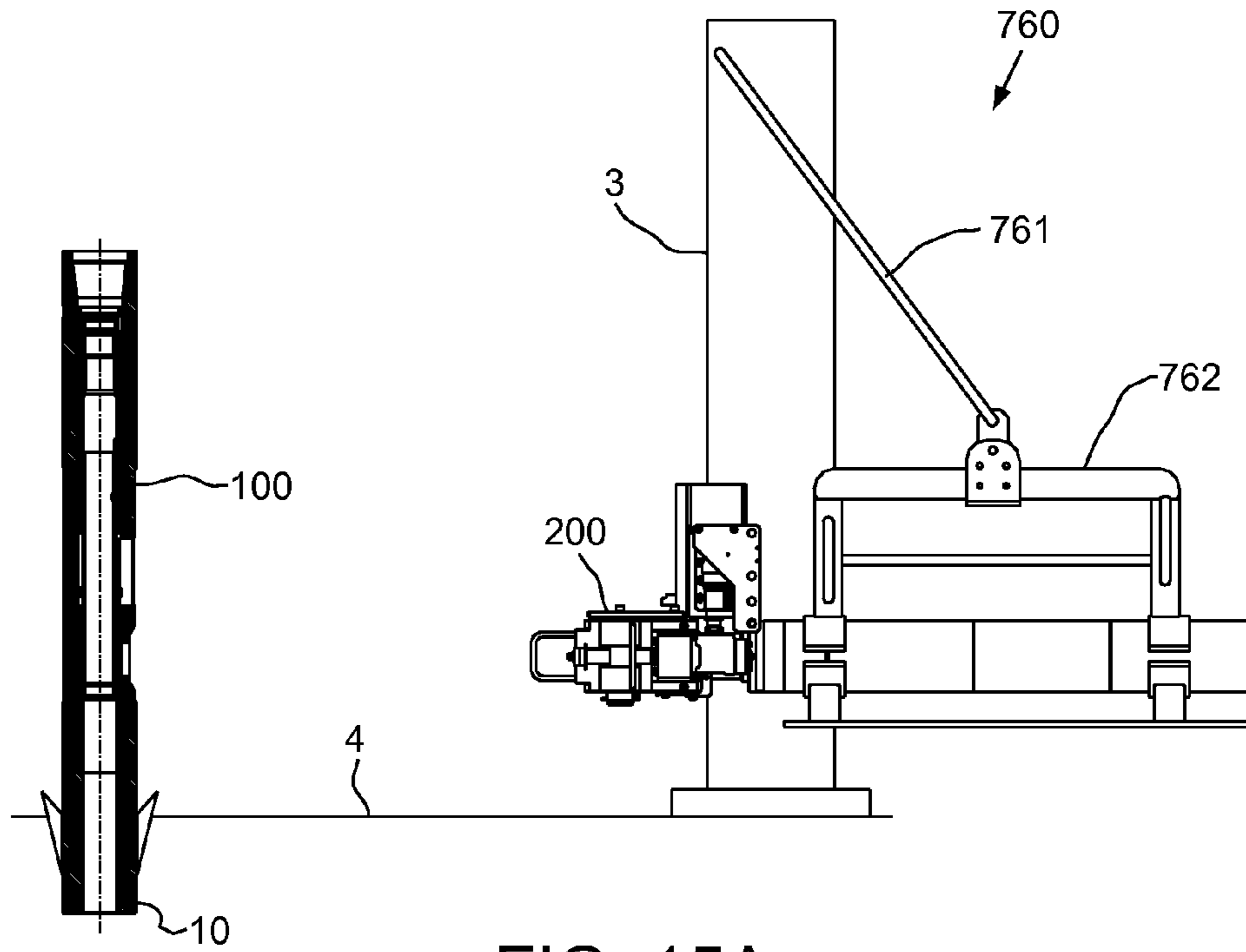


FIG. 15A

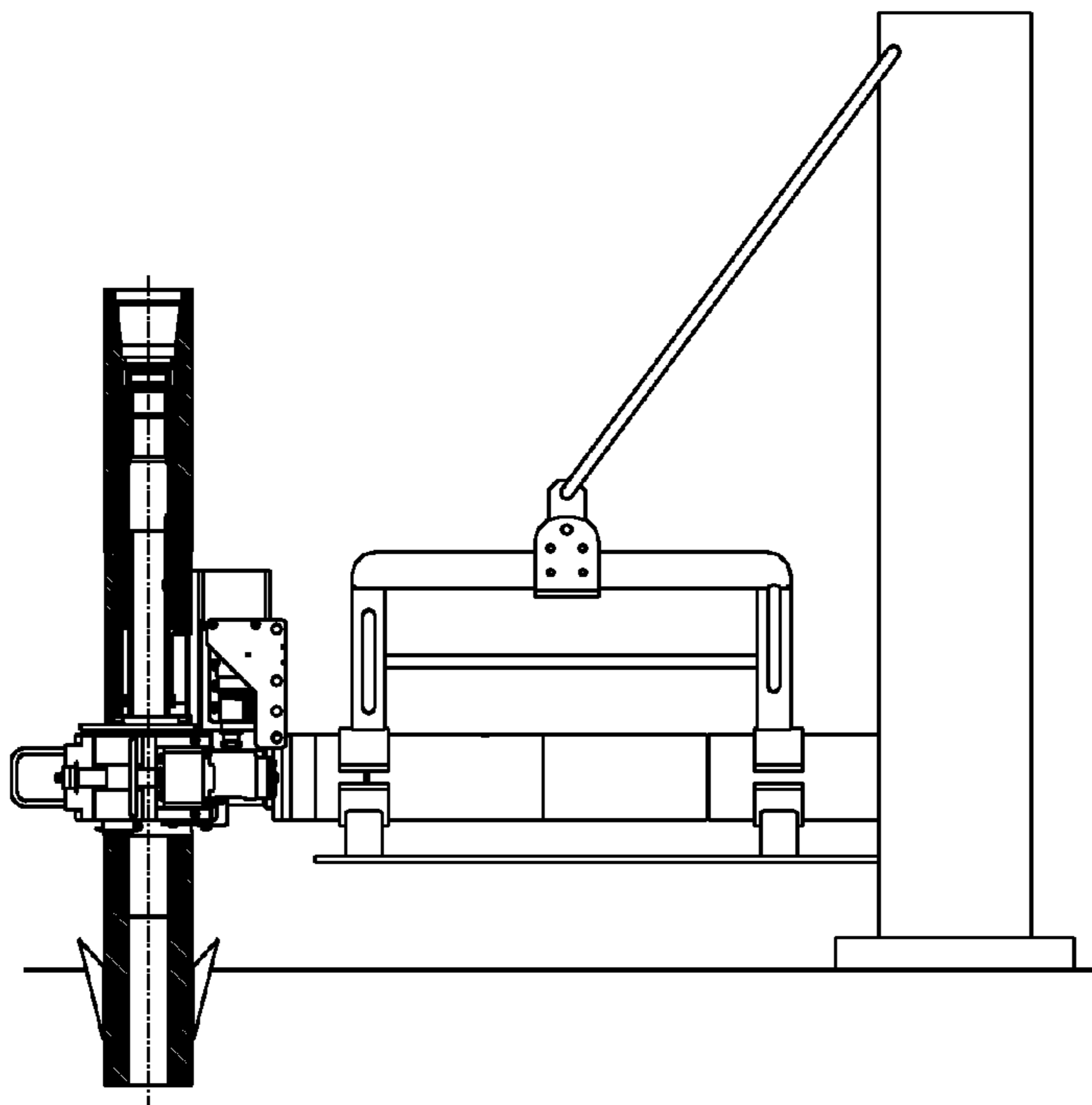


FIG. 15B

CONTINUOUS FLOW SYSTEM FOR DRILLING OIL AND GAS WELLS

BACKGROUND OF THE DISCLOSURE

Field of the Disclosure

The present disclosure generally relates to a continuous flow system for drilling oil and gas wells.

Description of the Related Art

In many drilling operations to recover hydrocarbons, a drill string made by assembling joints of drill pipe with threaded connections and having a drill bit at the bottom is rotated to move the drill bit. Typically drilling fluid, such as oil or water based mud, is circulated to and through the drill bit to lubricate and cool the bit and to facilitate the removal of cuttings from the wellbore that is being formed. The drilling fluid and cuttings returns to the surface via an annulus formed between the drill string and the wellbore. At the surface, the cuttings are removed from the drilling fluid and the drilling fluid is recycled.

As the drill bit penetrates into the earth and the wellbore is lengthened, more joints of drill pipe are added to the drill string. This involves stopping the drilling while the joints are added. The process is reversed when the drill string is removed or tripped, e.g., to replace the drill bit or to perform other wellbore operations. Interruption of drilling may mean that the circulation of the mud stops and has to be re-started when drilling resumes. This can be time consuming, can cause deleterious effects on the walls of the wellbore being drilled, and can lead to formation damage and problems in maintaining an open wellbore. Also, a particular mud weight may be chosen to provide a static head relating to the ambient pressure at the top of a drill string when it is open while joints are being added or removed. The weighting of the mud can be very expensive.

To convey drilled cuttings away from a drill bit and up and out of a wellbore being drilled, the cuttings are maintained in suspension in the drilling fluid. If the flow of fluid with cuttings suspended in it ceases, the cuttings tend to fall within the fluid. This is inhibited by using relatively viscous drilling fluid; but thicker fluids require more power to pump. Further, restarting fluid circulation following a cessation of circulation may result in the overpressuring of a formation in which the wellbore is being formed.

SUMMARY OF THE DISCLOSURE

The present disclosure generally relates to a continuous flow system for drilling oil and gas wells. In one embodiment, a flow sub for use with a drill string includes a tubular housing having a longitudinal bore therethrough and a flow port through a wall thereof and a ball. The ball is disposed in the housing above the flow port, has a bore therethrough, and is rotatable relative to the housing between an open position where the ball bore is aligned with the housing bore and a closed position where a wall of the ball blocks the housing bore. The flow sub further includes a seat disposed in the housing above the ball for sealing against the ball wall in the closed position and a sleeve disposed in the housing and movable between an open position where the flow port is exposed to the housing bore and a closed position where a wall of the sleeve is disposed between the flow port and the housing bore.

In another embodiment, a flow sub for use with a drill string includes: a tubular housing having a longitudinal bore therethrough and a flow port through a wall thereof; a cage disposed in the housing and having a port in alignment with

the flow port; and a three-way ball. The three-way ball is disposed in the cage, has a bore therethrough and a side opening carved from a wall thereof, and is rotatable relative to the housing between a top injection position where the ball bore is aligned with the housing bore and a wall of the ball blocks the side port and a bypass position where the side opening is aligned with the flow port and the ball wall blocks the housing bore. The flow sub further includes: a seat disposed in the housing above the ball for sealing against the ball wall in the bypass position and a flange of the ball in the top injection position; a port seal carried by the cage adjacent to the cage port for sealing against the ball wall in the bypass position; and a pair of pivot pins connecting the ball to the housing. One of the pivot pins has a torsional profile accessible from an exterior of the housing.

In another embodiment, an iron roughneck of a continuous flow system includes: a frame; a backup tong mounted to the frame; a wrenching tong supported by the backup tong and rotatable relative thereto; a spinner mounted to the frame; and a flow sub tong. The flow sub tong includes: a body mounted to the frame; an inlet connected to the body for injecting fluid into a flow port of a flow sub and operable to seal against a surface of a housing of the flow sub adjacent to the flow port; a plurality of clamping jaws operable to engage the housing; and an automated port valve actuator connected to the body and operable to move a sleeve of the flow sub.

BRIEF DESCRIPTION OF THE DRAWINGS

So that the manner in which the above recited features of the present disclosure can be understood in detail, a more particular description of the disclosure, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this disclosure and are therefore not to be considered limiting of its scope, for the disclosure may admit to other equally effective embodiments.

FIGS. 1A-1C illustrates a drilling system in a drilling mode, according to one embodiment of the present disclosure.

FIGS. 2A and 2B illustrate a flow sub of the drilling system in a top injection mode.

FIGS. 3A-3D illustrates a clamp of the drilling system.

FIGS. 4A-4H illustrates operation of the flow sub and the clamp.

FIG. 5A illustrates the drilling system in a bypass mode. FIGS. 5B and 5C illustrate shifting of the drilling system between the modes.

FIGS. 6A-6D illustrates a first alternative flow sub for use with the clamp, according to another embodiment of the present disclosure.

FIGS. 7A-7I illustrates operation of the first alternative flow sub.

FIGS. 8A-8D illustrates a second alternative flow sub, according to another embodiment of the present disclosure.

FIGS. 9A-9D illustrates a third alternative flow sub, according to another embodiment of the present disclosure.

FIGS. 10A-10F illustrates a fourth alternative flow sub, according to another embodiment of the present disclosure.

FIG. 11A illustrates a fourth alternative clamp, according to another embodiment of the present disclosure. FIGS. 11B and 11C illustrate proximity sensors of the fourth alternative clamp.

FIGS. 12A and 12B illustrate a fifth alternative flow sub, according to another embodiment of the present disclosure.

3

FIG. 13A illustrates an iron roughneck for use with the flow sub instead of the clamp, according to another embodiment of the present disclosure. FIGS. 13B-13D illustrates engagement of the iron roughneck with the flow sub.

FIGS. 14A and 14B illustrate a rover for use with the flow sub instead of the clamp, according to another embodiment of the present disclosure.

FIGS. 15A and 15B illustrate a handler for use with the clamp, according to another embodiment of the present disclosure.

DETAILED DESCRIPTION

FIGS. 1A-1C illustrates a drilling system 1 in a drilling mode, according to one embodiment of the present disclosure. The drilling system 1 may include a mobile offshore drilling unit (MODU) 1*m*, such as a semi-submersible, a drilling rig 1*r*, a fluid handling system 1*h*, a fluid transport system 1*t*, and a pressure control assembly (PCA) 1*p*. The MODU 1*m* may carry the drilling rig 1*r* and the fluid handling system 1*h* aboard and may include a moon pool, through which drilling operations are conducted. The semi-submersible MODU 1*m* may include a lower barge hull which floats below a surface (aka waterline) 2*s* of sea 2 and is, therefore, less subject to surface wave action. Stability columns (only one shown) may be mounted on the lower barge hull for supporting an upper hull above the waterline. The upper hull may have one or more decks for carrying the drilling rig 1*r* and fluid handling system 1*h*. The MODU 1*m* may further have a dynamic positioning system (DPS) (not shown) or be moored for maintaining the moon pool in position over a subsea wellhead 50.

Alternatively, the MODU may be a drill ship. Alternatively, a fixed offshore drilling unit or a non-mobile floating offshore drilling unit may be used instead of the MODU 1*m*. Alternatively, the wellbore may be subsea having a wellhead located adjacent to the waterline and the drilling rig may be located on a platform adjacent the wellhead. Alternatively, the drilling system may be used for drilling a subterranean (aka land based) wellbore and the MODU 1*m* may be omitted.

The drilling rig 1*r* may include a derrick 3 having a rig floor 4 at its lower end having an opening corresponding to the moonpool. The drilling rig 1*r* may further include a top drive 5. The top drive 5 may include a motor for rotating 16 a drill string 10. The top drive motor may be electric or hydraulic. A housing of the top drive 5 may be coupled to a rail (not shown) of the derrick 3 for preventing rotation of the top drive housing during rotation of the drill string 10 and allowing for vertical movement of the top drive with a traveling block 6. A housing of the top drive 5 may be suspended from the derrick 3 by the traveling block 6. The traveling block 6 may be supported by wire rope 7 connected at its upper end to a crown block 8. The wire rope 7 may be woven through sheaves of the blocks 6, 8 and extend to drawworks 9 for reeling thereof, thereby raising or lowering the traveling block 6 relative to the derrick 3. A Kelly valve 11 may be connected to a quill of a top drive 5. A top of the drill string 10 may be connected to the Kelly valve 11, such as by a threaded connection or by a gripper (not shown), such as a torque head or spear. The drilling rig 1*r* may further include a drill string compensator (not shown) to account for heave of the MODU 1*m*. The drill string compensator may be disposed between the traveling block 6 and the top drive 5 (aka hook mounted) or between the crown block 8 and the derrick 3 (aka top mounted).

4

The fluid transport system it may include the drill string 10, an upper marine riser package (UMRP) 20, a marine riser 25, a booster line 27, and a choke line 28. The drill string 10 may include a bottomhole assembly (BHA) 10*b*, joints of drill pipe 10*p* connected together, such as by threaded couplings (FIG. 5A), and one or more (four shown) flow subs 100. The BHA 10*b* may be connected to the drill pipe 10*p*, such as by a threaded connection, and include a drill bit 15 and one or more drill collars 12 connected thereto, such as by a threaded connection. The drill bit 15 may be rotated 16 by the top drive 5 via the drill pipe 10*p* and/or the BHA 10*b* may further include a drilling motor (not shown) for rotating the drill bit. The BHA 10*b* may further include an instrumentation sub (not shown), such as a measurement while drilling (MWD) and/or a logging while drilling (LWD) sub.

The PCA 1*p* may be connected to a wellhead 50 adjacently located to a floor 2*f* of the sea 2. A conductor string 51 may be driven into the seafloor 2*f*. The conductor string 51 may include a housing and joints of conductor pipe connected together, such as by threaded connections. Once the conductor string 51 has been set, a subsea wellbore 90 may be drilled into the seafloor 2*f* and a first casing string 52 may be deployed into the wellbore. The first casing string 52 may include a wellhead housing and joints of casing connected together, such as by threaded connections. The wellhead housing may land in the conductor housing during deployment of the first casing string 52. The first casing string 52 may be cemented 91 into the wellbore 90. The first casing string 52 may extend to a depth adjacent a bottom of an upper formation 94*u*. The upper formation 94*u* may be non-productive and a lower formation 94*b* may be a hydrocarbon-bearing reservoir. Alternatively, the lower formation 94*b* may be environmentally sensitive, such as an aquifer, or unstable. Although shown as vertical, the wellbore 90 may include a vertical portion and a deviated, such as horizontal, portion.

The PCA 1*p* may include a wellhead adapter 40*b*, one or more flow crosses 41*u,m,b*, one or more blow out preventers (BOPS) 42*a,u,b*, a lower marine riser package (LMRP), one or more accumulators 44, and a receiver 46. The LMRP may include a control pod 76, a flex joint 43, and a connector 40*u*. The wellhead adapter 40*b*, flow crosses 41*u,m,b*, BOPS 42*a,u,b*, receiver 46, connector 40*u*, and flex joint 43, may each include a housing having a longitudinal bore therethrough and may each be connected, such as by flanges, such that a continuous bore is maintained therethrough. The bore may have drift diameter, corresponding to a drift diameter of the wellhead 50.

Each of the connector 40*u* and wellhead adapter 40*b* may include one or more fasteners, such as dogs, for fastening the LMRP to the BOPS 42*a,u,b* and the PCA 1*p* to an external profile of the wellhead housing, respectively. Each of the connector 40*u* and wellhead adapter 40*b* may further include a seal sleeve for engaging an internal profile of the respective receiver 46 and wellhead housing. Each of the connector 40*u* and wellhead adapter 40*b* may be in electric or hydraulic communication with the control pod 76 and/or further include an electric or hydraulic actuator and an interface, such as a hot stab, so that a remotely operated subsea vehicle (ROV) (not shown) may operate the actuator for engaging the dogs with the external profile.

The LMRP may receive a lower end of the riser 25 and connect the riser to the PCA 1*p*. The control pod 76 may be in electric, hydraulic, and/or optical communication with a programmable logic controller (PLC) 75 onboard the MODU 1*m* via an umbilical 70. The control pod 76 may

include one or more control valves (not shown) in communication with the BOPS **42a,u,b** for operation thereof. Each control valve may include an electric or hydraulic actuator in communication with the umbilical **70**. The umbilical **70** may include one or more hydraulic or electric control conduit/cables for the actuators. The accumulators **44** may store pressurized hydraulic fluid for operating the BOPS **42a,u,b**. Additionally, the accumulators **44** may be used for operating one or more of the other components of the PCA **1p**. The umbilical **70** may further include hydraulic, electric, and/or optic control conduit/cables for operating various functions of the PCA **1p**. The PLC **75** may operate the PCA **1p** via the umbilical **70** and the control pod **76**.

A lower end of the booster line **27** may be connected to a branch of the flow cross **41u** by a shutoff valve **45a**. A booster manifold may also connect to the booster line lower end and have a prong connected to a respective branch of each flow cross **41m,b**. Shutoff valves **45b,c** may be disposed in respective prongs of the booster manifold. Alternatively, a separate kill line (not shown) may be connected to the branches of the flow crosses **41m,b** instead of the booster manifold. An upper end of the booster line **27** may be connected to an outlet of a booster pump (not shown). A lower end of the choke line **28** may have prongs connected to respective second branches of the flow crosses **41m,b**. Shutoff valves **45d,e** may be disposed in respective prongs of the choke line lower end.

A pressure sensor **47a** may be connected to a second branch of the upper flow cross **41u**. Pressure sensors **47b,c** may be connected to the choke line prongs between respective shutoff valves **45d,e** and respective flow cross second branches. Each pressure sensor **47a-c** may be in data communication with the control pod **76**. The lines **27, 28** and umbilical **70** may extend between the MODU **1m** and the PCA **1p** by being fastened to brackets disposed along the riser **25**. Each line **27, 28** may be a flow conduit, such as coiled tubing. Each shutoff valve **45a-e** may be automated and have a hydraulic actuator (not shown) operable by the control pod **76** via fluid communication with a respective umbilical conduit or the LMRP accumulators **44**. Alternatively, the valve actuators may be electrical or pneumatic.

The riser **25** may extend from the PCA **1p** to the MODU **1m** and may connect to the MODU via the UMRP **20**. The UMRP **20** may include a diverter **21**, a flex joint **22**, a slip (aka telescopic) joint **23**, a tensioner **24**, and a rotating control device (RCD) **26**. A lower end of the RCD **26** may be connected to an upper end of the riser **25**, such as by a flanged connection. The slip joint **23** may include an outer barrel connected to an upper end of the RCD **26**, such as by a flanged connection, and an inner barrel connected to the flex joint **22**, such as by a flanged connection. The outer barrel may also be connected to the tensioner **24**, such as by a tensioner ring (not shown).

The flex joint **22** may also connect to the diverter **21**, such as by a flanged connection. The diverter **21** may also be connected to the rig floor **4**, such as by a bracket. The slip joint **23** may be operable to extend and retract in response to heave of the MODU **1m** relative to the riser **25** while the tensioner **24** may reel wire rope in response to the heave, thereby supporting the riser **25** from the MODU **1m** while accommodating the heave. The flex joints **23, 43** may accommodate respective horizontal and/or rotational (aka pitch and roll) movement of the MODU **1m** relative to the riser **25** and the riser relative to the PCA **1p**. The riser **25** may have one or more buoyancy modules (not shown) disposed therealong to reduce load on the tensioner **24**.

The RCD **26** may include a housing, a piston, a latch, and a rider. The housing may be tubular and have one or more sections connected together, such as by flanged connections. The rider may include a bearing assembly, one or more stripper seals, and a catch, such as a sleeve. The rider may be selectively longitudinally and torsionally connected to the housing by engagement of the latch with the catch sleeve. The housing may have hydraulic ports in fluid communication with the piston and an interface of the RCD. The bearing assembly may be connected to the stripper seals. The bearing assembly may allow the stripper seals to rotate relative to the housing. The bearing assembly may include one or more radial bearings, one or more thrust bearings, and a self contained lubricant system.

Each stripper seal may be directional and oriented to seal against the drill pipe **10p** in response to higher pressure in the riser **25** than the UMRP **20** (components thereof above the RCD). In operation, the drill pipe **10p** may be received through the rider so that the stripper seals may engage the drill pipe in response to sufficient pressure differential. Each stripper seal may also be flexible enough to seal against an outer surface of the drill pipe **10p** having a pipe diameter and an outer surface of threaded couplings of the drill pipe having a larger tool joint diameter. The RCD **26** may provide a desired barrier in the riser **25** either when the drill pipe is stationary or rotating. Alternatively, an active seal RCD may be used. The RCD housing may be submerged adjacent the waterline **2s**. The RCD interface may be in fluid communication with an auxiliary hydraulic power unit (HPU) (not shown) of the PLC **75** via an auxiliary umbilical **71**.

Alternatively, the rider may be non-releasably connected to the housing. Alternatively, the RCD may be located above the waterline and/or along the UMRP at any other location besides a lower end thereof. Alternatively, the RCD may be located at an upper end of the UMRP and the slip joint **23** and bracket connecting the UMRP to the rig may be omitted or the slip joint may be locked instead of being omitted. Alternatively, the RCD may be assembled as part of the riser at any location therealong.

The fluid handling system **1h** may include a return line **29**, mud pump **30d**, one or more hydraulic power units (HPUs) **30h** (one shown in FIG. 1A and two shown in FIG. 5A), a bypass line **31p,h**, one or more hydraulic lines **31c**, a drain line **32**, a solids separator, such as a shale shaker **33**, one or more flow meters **34b,d,r**, one or more pressure sensors **35b,d,r**, one or more variable choke valves, such as chokes **36f,r**, an overpressure valve **36p**, a supply line **37p,h**, one or more shutoff valves **38a-d**, a hydraulic manifold **39**, one or more check valves **65a,b** and a clamp **200**.

A lower end of the return line **29** may be connected to an outlet of the RCD **26** and an upper end of the return line may be connected to an inlet of the mud pump **30d**. The returns pressure sensor **35r**, returns choke **36r**, returns flow meter **34r**, and shale shaker **33** may be assembled as part of the return line **29**. Alternatively, the return line **29** may further include a gas detector. The gas detector may include a probe having a membrane for sampling gas from the returns **60r**, a gas chromatograph, and a carrier system for delivering the gas sample to the chromatograph. A lower end of the supply line **37p,h** may be connected to an outlet of the mud pump **30d** and an upper end of the supply line may be connected to an inlet of the top drive **5**. The supply pressure sensor **35d**, supply flow meter **34d**, and supply shutoff valve **38a** may be assembled as part of the supply line **37p,h**. A first end of the bypass line **31p,h** may be connected to an outlet of the mud pump **30d** and a second end of the bypass line may be connected to an inlet **207** (FIG. 3A) of the clamp **200**. The

bypass pressure sensor **35b**, bypass flow meter **34b**, and bypass shutoff valve **38b** may be assembled as part of the bypass line **31p,h**.

A first end of the drain line **32** may be connected to the return line **29** and a second portion of the drain line may have prongs (four shown). A first drain prong may be connected to the bypass line **31p,h**. A second drain prong may be connected to the supply line **37p,h**. Third and fourth drain prongs may be connected to an outlet of the mud pump **30d**. The supply drain valve **38c**, bypass drain valve **38d**, overpressure valve **36p**, flow choke **36f**, and check valves **65a,b** may be assembled as part of the drain line **32**. A first end of the hydraulic lines **31c** may be connected to the HPU **30h** and a second end of the hydraulic lines may be connected to the clamp **200**. The hydraulic manifold **39** may be assembled as part of the hydraulic lines **31c**.

Each choke **36f,r** may include a hydraulic actuator operated by the PLC **75** via the auxiliary HPU (not shown). The returns choke **36r** may be operated by the PLC to maintain backpressure in the riser **25**. The flow choke **36f** may be operated (FIG. **5B**) by the PLC **75** to prevent a flow rate supplied to the flow sub **100** and clamp **200** in bypass mode (FIG. **5A**) from exceeding a maximum allowable flow rate of the flow sub and/or clamp. Alternatively, the choke actuators may be electrical or pneumatic. The overpressure valve **36p** may be a shutoff valve and have a hydraulic actuator (not shown) operable by the PLC **75** via the auxiliary HPU to protect against overpressure of the clamp **200** by the mud pump **30d**. Each shutoff valve **38a-d** may be automated and have a hydraulic actuator (not shown) operable by the PLC **75** via the auxiliary HPU. Alternatively, the valve actuators may be electrical or pneumatic.

Each pressure sensor **35b,d,r** may be in data communication with the PLC **75**. The returns pressure sensor **35r** may be operable to measure backpressure exerted by the returns choke **36r**. The supply pressure sensor **35d** may be operable to measure standpipe pressure. The bypass pressure sensor **35b** may be operable to measure pressure of the clamp inlet **207**. The returns flow meter **34r** may be a mass flow meter, such as a Coriolis flow meter, and may be in data communication with the PLC **75**. The returns flow meter **34r** may be connected in the return line **29** downstream of the returns choke **36r** and may be operable to measure a flow rate of the returns **60r**. Each of the supply **34d** and bypass **34b** flow meters may be a volumetric flow meter, such as a Venturi flow meter. The supply flow meter **34d** may be operable to measure a flow rate of drilling fluid supplied by the mud pump **30d** to the drill string **10** via the top drive **5**. The bypass flow meter **34b** may be operable to measure a flow rate of drilling fluid supplied by the mud pump **30d** to the clamp inlet **207**. The PLC **75** may receive a density measurement of the drilling fluid **60d** from a mud blender (not shown) to determine a mass flow rate of the drilling fluid. Alternatively, the bypass **34b** and supply **34d** flow meters may each be mass flow meters.

In the drilling mode, the mud pump **30d** may pump drilling fluid **60d** from the shaker **33** (or fluid tank connected thereto), through the pump outlet, standpipe **37p** and Kelly hose **37h** to the top drive **5**. The drilling fluid **60d** may include a base liquid. The base liquid may be base oil, water, brine, or a water/oil emulsion. The base oil may be diesel, kerosene, naphtha, mineral oil, or synthetic oil. The drilling fluid **60d** may further include solids dissolved or suspended in the base liquid, such as organophilic clay, lignite, and/or asphalt, thereby forming a mud.

The drilling fluid **60d** may flow from the Kelly hose **37h** and into the drill string **10** via the top drive **5** and Kelly valve

11. The drilling fluid **60d** may flow down through the drill string **10** and exit the drill bit **15**, where the fluid may circulate the cuttings away from the bit and return the cuttings up an annulus **95** formed between an inner surface of the casing **91** or wellbore **90** and an outer surface of the drill string **10**. The returns **60r** (drilling fluid **60d** plus cuttings) may flow through the annulus **95** to the wellhead **50**. The returns **60r** may continue from the wellhead **50** and into the riser **25** via the PCA **1p**. The returns **60r** may flow up the riser **25** to the RCD **26**. The returns **60r** may be diverted by the RCD **26** into the return line **29** via the RCD outlet. The returns **60r** may continue through the returns choke **36r** and the flow meter **34r**. The returns **60r** may then flow into the shale shaker **33** and be processed thereby to remove the cuttings, thereby completing a cycle. As the drilling fluid **60d** and returns **60r** circulate, the drill string **10** may be rotated **16** by the top drive **5** and lowered by the traveling block **6**, thereby extending the wellbore **90** into the lower formation **94b**.

The PLC **75** may be programmed to operate the returns choke **36r** so that a target bottomhole pressure (BHP) is maintained in the annulus **95** during the drilling operation. The target BHP may be selected to be within a drilling window defined as greater than or equal to a minimum threshold pressure, such as pore pressure, of the lower formation **94b** and less than or equal to a maximum threshold pressure, such as fracture pressure, of the lower formation, such as an average of the pore and fracture BHPs. Alternatively, the minimum threshold may be stability pressure and/or the maximum threshold may be leakoff pressure. Alternatively, threshold pressure gradients may be used instead of pressures and the gradients may be at other depths along the lower formation **94b** besides bottomhole, such as the depth of the maximum pore gradient and the depth of the minimum fracture gradient. Alternatively, the PLC **75** may be free to vary the BHP within the window during the drilling operation.

A static density of the drilling fluid **60d** (typically assumed equal to returns **60r**; effect of cuttings typically assumed to be negligible) may correspond to a threshold pressure gradient of the lower formation **94b**, such as being equal to a pore pressure gradient. Alternatively, a static density of the drilling fluid **60d** may be slightly less than the pore pressure gradient such that an equivalent circulation density (ECD) (static density plus dynamic friction drag) during drilling is equal to the pore pressure gradient. Alternatively, a static density of the drilling fluid **60d** may be slightly greater than the pore pressure gradient. During the drilling operation, the PLC **75** may execute a real time simulation of the drilling operation in order to predict the actual BHP from measured data, such as standpipe pressure from sensor **35d**, mud pump flow rate from the supply flow meter **34d**, wellhead pressure from an of the sensors **47a-c**, and return fluid flow rate from the return flow meter **34r**. The PLC **75** may then compare the predicted BHP to the target BHP and adjust the returns choke **36r** accordingly.

During the drilling operation, the PLC **75** may also perform a mass balance to monitor for a kick (not shown) or lost circulation (not shown). As the drilling fluid **60d** is being pumped into the wellbore **90** by the mud pump **30d** and the returns **60r** are being received from the return line **29**, the PLC **75** may compare the mass flow rates (i.e., drilling fluid flow rate minus returns flow rate) using the respective flow meters **34d,r**. The PLC **75** may use the mass balance to monitor for formation fluid (not shown) entering the annulus **95** and contaminating the returns **60r** or returns **60r** entering the formation **94b**.

Upon detection of either event, the PLC 75 may take remedial action, such as diverting the flow of returns 60r from an outlet of the returns flow meter to a degassing spool (not shown). The degassing spool may include automated shutoff valves at each end and a mud-gas separator (MGS). A first end of the degassing spool may be connected to the returns line 29 between the returns flow meter and the shaker 33 and a second end of the degasser spool may be connected to an inlet of the shaker. The MGS may include an inlet and a liquid outlet assembled as part of the degassing spool and a gas outlet connected to a flare or a gas storage vessel. The PLC 75 may also adjust the returns choke 36r accordingly, such as tightening the choke in response to a kick and loosening the choke in response to loss of the returns.

Alternatively, the PLC 75 may estimate a mass rate of cuttings (and add the cuttings mass rate to the intake sum) using a rate of penetration (ROP) of the drill bit or a mass flow meter may be added to the cuttings chute of the shaker and the PLC may directly measure the cuttings mass rate.

FIGS. 2A and 2B illustrate the flow sub 100 in a top injection mode. The flow sub 100 may include a tubular housing 105, a bore valve 110, a bore valve actuator, and a side port valve 120. The housing 105 may include one or more sections, such as an upper section 105u and a lower 105b section, each section connected together, such as by a threaded connection. An outer diameter of the housing 105 may correspond to the tool joint diameter of the drill pipe 10p to maintain compatibility with the RCD 26. The housing 105 may have a central longitudinal bore formed there-through and a radial flow port 101 formed through a wall thereof in fluid communication with the bore (when the port valve is open) and located at a side of the lower housing section 105b. Alternatively, the side port 101 may be inclined between the radial and longitudinal axes of the housing 105. The housing 105 may also have a threaded coupling at each longitudinal end, such as box 106b formed in an upper longitudinal end and a pin 106p formed on a lower longitudinal end, so that the housing may be assembled as part of the drill string 10. Except for seals and where otherwise specified, the flow sub 100 may be made from a metal or alloy, such as steel, stainless steel, or a nickel based alloy. Seals may be made from an elastomer or elastomeric copolymer and may include backup rings and/or energizing springs.

A length of the housing 105 may be equal to or less than the length of a standard joint of drill pipe 10p. A length of the housing 105 may be substantially less than the length of a standard joint of drill pipe 10p, such as less than or equal to one-third or one-sixth the length, so that the flow sub 100 may be connected to one or more joints of drill pipe 10p to form a stand 10s with only a negligible increase in length than if the stand was formed without the flow sub. The compactness of the flow sub 100 allows the stand 10s to have the same number of drill pipe joints as a stand that would be normally used with the rig 1r.

The bore valve 110 may include a closure member, such as a ball 111, a seat 112, a body 109, 113, and a fastener 114. The body 109, 113 may include one or more sections, such as an upper tube section 109 and a lower sleeve section 113. The lower body section 113 may be disposed within the housing 105 and connected thereto. The lower body section 113 may have a lip 113p formed in an outer surface thereof and a threaded coupling formed in the outer surface adjacently below the lip. The lower housing section 105b may have a threaded coupling formed in an inner surface thereof and adjacent to an upper end 103b thereof for mating with

the lower body section threaded coupling. A lower face of the lip 113p may also receive the upper end 103b.

Upper seals 124u may be disposed between the housing 105 and the cam 115 and between the upper body section 113u and the cam to isolate the interfaces thereof. The upper housing section 105u may have a shoulder 103u formed in an inner surface thereof and adjacently below the box 106b. The shoulder 103u may have a tapered upper face and a flat lower face. The fastener 114 may be annular and have a threaded coupling formed in an outer surface thereof and extending from a lower end thereof and a tapered shoulder formed in the outer surface and extending from an upper end thereof.

The upper body section 109 may be disposed within the housing 105 and have a threaded coupling formed in an inner surface thereof and extending from an upper end thereof. Mating of the fastener thread with the upper body thread and engagement of the fastener shoulder with the housing shoulder 103u may connect the upper body section 109 to the housing 105. The seat 112 may include a seal 112s and a retainer 112r. The upper body section 109 may have a recess formed in an inner surface thereof and extending from a bottom thereof for receiving the seat retainer 112r. The seat retainer 112r may be connected to the upper body section 109, such as by press fit or a threaded connection. The seat seal 112s may be connected to the upper body section 109, such as by a lip and groove connection and by being disposed between the upper body section and the seat retainer 112r. The seat seal 112s may be annular and have a tapered inner surface conforming to an outer surface of the ball 111 for sealing engagement therewith. The lower body section 113 may have a tapered stop shoulder 113s formed in an inner surface thereof, extending from an upper end thereof, and conforming to the ball outer surface. Alternatively, a lower seat may be used instead of the stopper 113s.

The ball 111 may be disposed between the body sections 109, 113 and may be rotatable relative thereto. The ball 111 may be operable between an open position (FIGS. 2A, 4A, 4B, 4E, and 4F) and a closed position (FIGS. 4D, and 5A) by the bore valve actuator. The ball 111 may have a bore formed therethrough corresponding to the housing bore and aligned therewith in the open position. A wall of the ball 111 may close an upper portion of the housing bore in the closed position and the ball may engage the seat seal 112s in response to pressure exerted against the ball by fluid injection into the side port 101.

The port valve 120 may include a closure member, such as a sleeve 121, and a seal mandrel 122. The seal mandrel 122 may be made from an erosion resistant material, such as tool steel, ceramic, or cermet. The seal mandrel 122 may be disposed within the housing 105 and connected thereto, such as by one or more (two shown) fasteners 123. The seal mandrel 122 may have a port formed through a wall thereof corresponding to and aligned with the side port 101. Lower seals 124b may be disposed between the housing 105 and the seal mandrel 122 and between the seal mandrel and the sleeve 121 to isolate the interfaces thereof. The port valve 120 may have a maximum allowable flow rate greater than, equal to, or slightly less than a flow rate of the drilling fluid 60d in drilling mode.

The valve sleeve 121 may be disposed within the housing 105 and longitudinally moveable relative thereto between an open position (FIG. 4D) and a closed position (FIGS. 2A, 2B, 4A, and 4H) by the clamp 200. In the open position, the side port 101 may be in fluid communication with a lower portion of the housing bore. In the closed position, the valve sleeve 121 may isolate the side port 101 from the housing

11

bore by engagement with the lower seals **124b** of the seal sleeve **122**. The valve sleeve **121** may include an upper portion **121u**, a lower portion **121b**, and a lug **121c** disposed between the upper and lower portions.

A window **102** may be formed through a wall of the lower housing section **105b** and may extend a length corresponding to a stroke of the port valve **120**. The window **102** may be aligned with the side port **101**. The lug **121c** may be accessible through the window **102**. A recess **104** may be formed in an outer surface of the lower housing section **105b** adjacent to the side port **101** for receiving a stab connector **209** formed at an end of an inlet **207** of the clamp **200**. Mid seals **124m** may be disposed between the housing **105** and the lower body section **113b** and between the lower body section and the sleeve **121** to isolate the interfaces thereof.

The bore valve actuator may be mechanical and include a cam **115**, one or more (two shown) followers **118**, a linkage, and a toggle. An upper annulus may be formed between the body **109**, **113** and the upper housing section **105u** and a lower annulus may be formed between the valve sleeve **121** and the lower housing section **105b**. The cam **115** may be disposed in the upper annulus and may be longitudinally movable relative to the housing **105**. Each follower **118** may be a threaded fastener connected to the cam **115** by being received in a threaded socket thereof. The cam **115** may interact with the ball **111**, such as by the followers **118** extending into a respective cam profile (not shown) formed in an outer surface of the ball **111** or vice versa. The ball-cam interaction may rotate the ball **111** between the open and closed positions in response to longitudinal movement of the cam **115** relative to the ball. The cam **115** may have a recess formed in an inner surface thereof to accommodate interaction with the ball and one or more windows (not shown) to facilitate assembly therewith.

The cam **115** may also interact with the valve sleeve **121** via the linkage and the toggle. The linkage may include one or more (two shown) pins **116**, inner slots **121s**, and outer slots **113k**. The toggle may include one or more (one shown) pins **117**, one or more (two shown) slots **113t** and sockets **121k**, and a groove **103g**. Each linkage pin **116** may be threaded and connected to the cam **115** by being received in a threaded socket thereof. A shank of each linkage pin **116** may extend through the respective outer slot **113k** formed through a wall of the lower body section **113** and into the respective inner slot **121s** formed through a wall of the sleeve upper portion **121u**.

Each toggle pin **117** may be longitudinally connected to the cam **115** by extending through a socket thereof. Each toggle pin **117** may be radially movable between an engaged position (FIGS. 4C-4E and 5A) and a disengaged position (FIGS. 2A, 4A, 4G, and 4H). Each toggle pin **117** may be aligned with the groove **103g** formed in an inner surface of the upper housing section **105u** in the disengaged position and float between engagement with an outer surface of the valve sleeve **121** and the groove. In the engaged position, a shank of each toggle pin **117** may be aligned with and extend into the respective toggle socket **121k** formed through a wall of the valve sleeve upper portion **121u**, thereby longitudinally connecting the valve sleeve **121** and the cam **115**. Each socket **121k** may be countersunk and the groove **103g** may have a tapered upper end for pushing the respective toggle pin **117** between the positions. The toggle sockets **121k** may be aligned with a bottom of the inner linkage slots **121s**. The linkage pins **116** and toggle pins **117** may be aligned. The outer linkage slots **113k** and toggle slots **113t** may be aligned

12

and have equal widths and lengths. The toggle and linkage members may be spaced around the flow sub **100** in an alternating fashion.

During an upstroke (FIGS. 4A-4D) of the flow sub **100**, the linkage may longitudinally connect the cam **115** and the valve sleeve **121** after allowing a predetermined amount of longitudinal movement therebetween. A stroke of the cam **115** may be less than a stroke of the valve sleeve **121**, such that when coupled with the lag created by the linkage, the bore valve **110** and the port valve **120** may never both be fully closed simultaneously (FIG. 4B). During a downstroke (FIGS. 4E-4H) of the flow sub **100**, the engaged toggle may longitudinally connect the cam **115** and the valve sleeve **121** before disengaging such that the bore valve **110** and the port valve **120** may never both be fully closed simultaneously (FIG. 4F).

FIGS. 3A-3D illustrates the clamp **200**. The clamp **200** may include a body **201**, a band **202**, a latch **205** operable to fasten the band to the body, an inlet **207**, one or more actuators, such as port valve actuator **210** and a band actuator **220**, and a hub **239**. The clamp **200** may be movable between an open position (not shown) for receiving the flow sub **100** and a closed position for surrounding an outer surface of the lower housing segment **105b**. The body **201** may have a lower base portion **201b** and an upper stem portion **201s**. The body **201** may have a coupling, such as a hinge portion, formed at an end of the base portion **201b**, and the band **202** may have a mating coupling, such as a hinge portion, formed at a first end thereof. The hinge portions may be connected by a fastener, such as a pin **204**, thereby pivotally connecting the band **202** and the body **201**. The band **202** may have a lap formed at a second end thereof for mating with a complementary lap formed at an end of the latch **205**. Engagement of the laps may form a lap joint to circumferentially connect the band **202** and the latch **205**.

The body **201** may have a port **201p** formed through the base portion **201b** for receiving the inlet **207**. The inlet **207** may be connected to the body **201**, such as by a threaded connection. A mud saver valve (MSV) **238** may be connected to the inlet **207**, such as by a threaded connection. An adapter **231** may be connected to the MSV **238** such as by a threaded connection. The adapter **231** may have a coupling, such as flange, for receiving a flexible conduit, such as bypass hose **31h**. The inlet **207** may further have one or more seals **208a,b** and a stab connector **209** formed at an end thereof engaging a seal face of the flow sub **100** adjacent to the side port **101**.

The port valve actuator **210** may include the stem portion **201s**, a bracket **212**, a yoke **213**, a hydraulic motor **215**, and a gear train **216**, **217**. The body **201** may have a window formed through the stem portion **201s** and guide profiles, such as tracks **211**, formed in an inner surface of the stem portion adjacent to the window. The yoke **213** may extend through the window and have a nut portion **213n**, slider portion **213s**, and tongue portion **213t**. The slider portion **213s** may be engaged with the tracks **211**, thereby allowing longitudinal movement of the yoke **213** relative to the body **201**. The yoke **213** may have an engagement profile, such as a lip **213p**, formed at an end of the tongue portion **213t** for engaging a groove formed in an outer surface of the lug **121c**, thereby longitudinally connecting the yoke with the flow sub sleeve **121**. The hydraulic motor **215** may have a stator connected to the bracket **212**, such as by one or more (four shown) fasteners **214**, and a rotor connected to a drive gear **216** of the gear train **216**, **217**. The motor **215** may be bidirectional.

The drive gear **216** may be connected to a yoke gear **217** by meshing of teeth thereof. The yoke gear **217** may be connected to a lead screw **218**, such as by interference fit or key/keyway. The nut portion **213n** may be engaged with the lead screw **218** such that the yoke **213** may be being raised and lowered by respective rotation of the lead screw. The bracket **212** may be connected to the body **201**, such as by one or more (three shown) fasteners **240**. The lead screw **218** may be supported by the bracket **212** for rotation relative thereto by one or more bearings **219** (FIG. 4A). The motor **215** may be operable to raise and lower the yoke **213** relative to the body **201**, thereby also operating the flow sub sleeve **121** when the clamp **200** is engaged with the flow sub **100** (FIGS. 4A-4F). Alternatively, the motor **215** may be electric or pneumatic.

The band actuator **220** may be operable to tightly engage the clamp **200** with the lower housing section **105b** after the latch **105** has been fastened. The band actuator **220** may include a bracket **222**, a hydraulic motor **225**, a bearing **229**, and a tensioner **224a,b, 226**. The tensioner **224a,b, 226** may include a tensioner bolt **224a**, a stopper **224b**, and a tubular tensioner nut **226**. The motor **225** may have a stator connected to the bearing **229**, such as by one or more fasteners (not shown) and a rotor connected to a tensioner bolt **224a**. The motor **225** may be bidirectional. The tensioner bolt **224a** may be supported from the body **201** for rotation relative thereto by the bearing **229**. The bracket **222** may be connected to the body **201**, such as by one or more (five shown) fasteners **241**. The bearing **229** may be connected to the bracket **222**, such as by a fastener **242**.

The latch **205** may include an opening formed therethrough for receiving the tensioner nut **226** and a cavity formed therein for facilitating assembly of the tensioner **224a,b, 226**. To further facilitate assembly, the tensioner nut **226** may be connected to a bar **227**, such as by fastener **244b** and a pin (slightly visible in FIG. 3B). The bar **227** may have a slot formed therethrough to accommodate operation of the tensioner **224a,b, 226**. The bar **227** may also be connected to the bracket, such as by fastener **244a**. The tensioner nut **226** may rotate relative to the opening and may have a threaded bore for receiving the tensioner bolt **224a**. Rotation of the tensioner nut **226** may prevent binding of the tensioner bolt **224a** and may allow replacement due to wear. A stopper **224b** may be connected to the bolt **224a** with a threaded connection. To engage the clamp **200** with the flow sub **100**, the body **201** may be aligned with the flow sub **100**, the band **202** wrapped around the flow sub **100** and the latch **205** engaged with the band **202**. The motor **225** may then be operated, thereby tightening the clamp **200** around the lower housing section **105b**. Alternatively, the motor **225** may be electric or pneumatic.

To facilitate manual handling, the clamp **200** may further include one or more handles **230a-d**. A first handle **230a** may be connected to the band **202**, such as by a fastener. Second **230b** and third **230c** handles may be connected to the latch **205**, such as by respective fasteners. A fourth handle **230d** may be connected to the bracket **222**, such as by a fastener. A hub **239** may be connected to the bracket **212**, such as by one or more (two shown) fasteners **243**. The hub **239** may include one or more (four shown) hydraulic connectors **245** for receiving respective hydraulic lines **31c** from the hydraulic manifold **39**. The hub **239** may also include internal hydraulic conduits (not shown), such as tubing, connecting the connectors **245** to respective inlets and outlets of the hydraulic motors **215, 225**.

Each hydraulic motor **215, 225** may further include a motor lock operable between a locked position and an

unlocked position. Each motor lock may include a clutch torsionally connecting the respective rotor and the stator in the locked position and disengaging the respective rotor from the respective stator in the unlocked position. Each clutch may be biased toward the locked position and further include an actuator, such as a piston, operable to move the clutch to the unlocked position in response to hydraulic fluid being supplied to the respective motor. Alternatively each lock may have an additional hydraulic port for supplying the actuator.

Alternatively, the band **202** and latch **205** may be replaced by automated (i.e., hydraulic) jaws. Additionally, the clamp **200** may be deployed using a beam assembly. The beam assembly may include a one or more fasteners, such as bolts, a beam, such as an I-beam, a fastener, such as a plate, and a counterweight. The counterweight may be clamped to a first end of the beam using the plate and the bolts. A hole may be formed in the second end of the beam for connecting a cable (not shown) which may include a hook for engaging the hoist ring. One or more holes (not shown) may be formed through a top of the beam at the center for connecting a sling which may be supported from the derrick **3** by a cable. Using the beam assembly, the clamp **200** may be suspended from the derrick **3** and swung into place adjacent the flow sub **100** when needed for adding stands **10s** to the drill string **10** and swung into a storage position during drilling.

Alternatively, the clamp **200** may be deployed using a telescopic arm. The telescopic arm may include a piston and cylinder assembly (PCA) and a mounting assembly. The PCA may include a two stage hydraulic PCA mounted internally of the arm which may include an outer barrel, an intermediate barrel and an inner barrel. The inner barrel may be slidably mounted in the intermediate barrel which is, may be in turn, slidably mounted in the outer barrel. The mounting assembly may include a bearer which may be secured to a beam by two bolt and plate assemblies. The bearer may include two ears which accommodate trunnions which may project from either side of a carriage. In operation, the clamp **200** may be moved toward and away from the flow sub **100** by extending and retracting the hydraulic piston and cylinder.

FIGS. 4A-4H illustrates operation of the flow sub **100** and the clamp **200**. FIG. 5A illustrates the drilling system **1** in a bypass mode. FIGS. 5B and 5C illustrate shifting of the drilling system **1** between the modes. Referring specifically to FIG. 5A, the MSV **238** may be manually operated. A position sensor **250** may be operably coupled to the MSV **238** for determining a position (open or closed) of the MSV. The position sensor **250** may be in data communication with the PLC **75**. Alternatively, the MSV **238** may be automated.

The fluid handling system **1h** may further include a second HPU **30h** and a second manifold **39**. Although two HPUs **30h** and two manifolds **39** are shown for operation of the clamp **200**, the clamp **200** may be operated with only one HPU and one manifold as shown in FIG. 1A. Each HPU **30h** may include a pump, an accumulator, a check valve, a reservoir having hydraulic fluid, and internal hydraulic conduits connecting the pump, reservoir, accumulator, and check valve. Each HPU **30h** may further include a pressurized port in fluid communication with the respective accumulator and a drain port in fluid communication with the reservoir. Each hydraulic manifold **39** may include one or more automated shutoff valves **39a-d, 39e-h** in communication with the PLC **75**. Each manifold **39** may have a pressurized inlet in connected to a first respective pair of the shutoff valves and a drain inlet in fluid communication with a second respective pair of shutoff valves. Each manifold **39**

may also have first and second outlets, each outlet connected to a shutoff valve of each pair. A first portion of the hydraulic lines **31c** may connect respective inlets of the manifolds to respective inlets of the HPUs. A second portion of the hydraulic lines **31c** may connect respective outlets of the manifolds to respective hydraulic connectors **245** of the clamp hub **239**. Alternatively, each manifold **39** may include one or more directional control valves, each directional control valve consolidating two or more of the shutoff valves **39a-h**.

Referring specifically to FIGS. **4A** and **5A-5C**, once it is necessary to extend the drill string **10**, drilling may be stopped by stopping advancement and rotation **16** of the top drive **5** and removing weight from the drill bit **15**. A spider (not shown) may then be operated to engage the drill string **10**, thereby longitudinally supporting the drill string **10** from the rig floor **4**. The clamp **200** may then be transported to the flow sub **100** and closed around the flow sub lower housing section **105b**. The PLC **75** may then operate the band actuator **220** by opening manifold valves **39a,d**, thereby supplying hydraulic fluid to the band motor **225**. Operation of the band motor **225** may rotate the tensioner bolt **224a**, thereby tightening the clamp **200** into engagement with the flow sub lower housing **105b**. The PLC **75** may then lock the band motor **225**. The MSV **238** may be manually opened and then the rig crew may evacuate the rig floor **4**.

The PLC **75** may then test engagement of the seals **208a,b** by closing the bypass drain valve **38d** and by opening the bypass valve **38b** to pressurize the clamp inlet **207** and then closing the bypass valve. If the clamp seals **208a,b** are not securely engaged with the lower housing section **105b**, drilling fluid **60d** will leak past the clamp seals. The PLC **75** may verify sealing integrity by monitoring the bypass pressure sensor **35b**. The PLC may then reopen the bypass valve **38b** to equalize pressure on the valve sleeve **121**. The PLC **75** may then operate the port valve actuator **210** by opening manifold valves **39f,h**, thereby supplying hydraulic fluid to the port motor **215**. Operation of the port motor **215** may rotate the lead screw **218**, thereby raising the yoke **213**.

Referring specifically to FIG. **4B**, when moved upwardly by the yoke **213**, the sleeve **121** may move longitudinally relative to the cam **115** until the bottoms of the inner slots **121s** engage the linkage pins **116**, thereby longitudinally connecting the sleeve and the cam and aligning the toggle pins **117** with the sockets **121k**. Due to the lag, discussed above, drilling fluid **60d** may momentarily flow into the drill string **10** through both the side port **101** and the bore valve **110**.

Referring specifically to FIG. **4C**, continued upward movement of the sleeve **121** and the cam **115** may cause the toggle pins **117** to engage the tapered upper portion of the groove, thereby pushing the toggle pins inward into the sockets **121k**. A transition or line fit between heads of the toggle pins **117** and an inner surface of the upper housing section **105u** may trap the toggle pins in the engaged position. Also at this position, closing of the bore valve **110** has commenced.

Referring specifically to FIG. **4D**, upward movement of the sleeve **121** and the cam **115** may continue, thereby fully closing the bore valve **110**. The upward movement may be halted by engagement of an upper shoulder of the yoke **213** with an upper shoulder of the stem portion **201s** at which point the side port **101** is fully open.

Referring specifically to FIGS. **5A-5C**, once the side port **101** is fully open, the PLC **75** may lock the port motor **215** and relieve pressure from the top drive **5** by closing the supply valve **38a** and opening the supply drain valve **38c**.

The PLC **75** may then test integrity of the closed bore valve **110** by closing the supply drain valve **38d**. If the bore valve **110** has not closed, drilling fluid **60d** will leak past the bore valve. The PLC **75** may verify closing of the bore valve **110** by monitoring the supply pressure sensor **35d**. The top drive **5** may then be operated to disconnect from the flow sub **100** and to hoist a stand **10s** from pipe rack **17**. The flow sub **100** may be assembled to form an upper end of the respective stand **10s**. The top drive **5** may continue to be operated to connect to the flow sub **100** of the retrieved stand **10s**. The top drive **5** may then be operated to connect a lower end of the stand **10s** to the flow sub **100** of the drill string **10**. Drilling fluid **60d** may continue to be injected into the side port **101** (via the open supply valve **38b** and MSV **238**) during adding of the stand **10s** by the top drive **5** at a flow rate corresponding to the flow rate in drilling mode. The PLC **75** may also utilize the bypass flow meter **34b** for performing the mass balance to monitor for a kick or lost circulation during adding of the stand **10s**.

Once the stand **10s** has been added to the drill string **10**, the PLC **75** may pressurize the added stand **10s** by closing the supply drain valve **38c** and opening the supply valve **38a**. Once the stand **10s** has been pressurized, the PLC **75** may then unlock the port motor **215**. The PLC **75** may then reverse operate the port valve actuator **210** by opening manifold valves **39e,g**, thereby reversing supply of the hydraulic fluid to the port motor **215**. Operation of the port motor **215** may counter-rotate the lead screw **218**, thereby lowering the yoke **213**.

Referring specifically to FIG. **4E**, lowering of the yoke **213** may cause downward movement of the valve sleeve **121** and the cam **115** due to the toggle pins **117** being engaged with the sockets **121k**. The bore valve **110** may commence opening upon downward movement of the cam **115**.

Referring specifically to FIG. **4F**, downward movement of the valve sleeve **121** and the cam **115** may continue, thereby fully opening the bore valve **110** and aligning the toggle pins **117** with the groove **103g**. Tapers in the sockets **121k** may push the toggle pins **117** outward into the groove **103g** once alignment has been reached, thereby releasing the cam **115** from the valve sleeve **121**. Alternatively, the toggle pins **117** may not be pushed into the groove **103g** until a bottom of the cam **115** engages a top face of the lip **113p**. Due to the toggle, discussed above, drilling fluid **60d** may momentarily flow into the drill string **10** through both the side port **101** and the bore valve **110**.

Referring specifically to FIG. **4G**, downward movement of the valve sleeve **121** relative to the freed cam **115** may continue until the tops of the inner slots **121s** engage the linkage pins **116**, thereby longitudinally connecting the sleeve and the cam.

Referring specifically to FIG. **4H**, downward movement of the sleeve **121** and the cam **115** may continue until a bottom of the cam **115** engages the top face of the lip **113p** at which point the side port **101** is fully closed.

Referring specifically to FIGS. **5A-5C**, once the side port **101** is fully closed, the PLC **75** may then relieve pressure from the clamp inlet **207** by closing the bypass valve **38b** and opening the bypass drain valve **38d**. The PLC **75** may then confirm closure of the valve sleeve **121** by closing the bypass drain valve **38d** and monitoring the bypass pressure sensor **35b**. Once closure of the valve sleeve **121** has been confirmed, the PLC **75** may open the bypass drain valve **38d**. The rig crew may then return to the rig floor **4** and close the MSV **238**. The PLC **75** may then unlock the band motor **225**. The PLC **75** may then reverse operate the band actuator **220** by opening manifold valves **39b,c**, thereby reversing supply

of hydraulic fluid to the band motor **225**. Operation of the band motor **225** may counter-rotate the tensioner bolt **224a**, thereby loosening the clamp **200** from engagement with the flow sub lower housing **105b**. The clamp **200** may then be opened and transported away from the flow sub **100**. The spider may then be operated to release the drill string **10**. Once released, the top drive **5** may be operated to rotate **16** the drill string **10**. Weight may be added to the drill bit **15**, thereby advancing the drill string **10** into the wellbore **90** and resuming drilling of the wellbore. The process may be repeated until the wellbore **90** has been drilled to total depth or to a depth for setting another string of casing.

A similar process may be employed if/when the drill string **10** needs to be tripped, such as for replacement of the drill bit **15** and/or to complete the wellbore **90**. To disassemble the drill string **10**, the drill string may be raised (while circulating drilling fluid via the top drive **5**) until one of the flow subs **100** is at the rig floor **4**. The spider may be set (if rotating **16** while tripping, rotation may be halted before setting the spider). The clamp **200** may be installed and tested. The drilling fluid flow may be switched to the clamp **200** and the bore valve **110** tested. The top drive **5** may then be operated to disconnect the stand **10s** extending above the rig floor **4** and to hoist the stand to the pipe rack **17**. The top drive **5** may then be connected to the flow sub **100** at the rig floor **4**. The top drive **5** may then be pressurized and the drilling fluid flow switched to the top drive. The clamp **200** may be bled, the port valve tested, and the clamp removed. Tripping of the drill string from the wellbore may then continue until the drill bit **15** reaches the LMRP. At that point, the BOPs may be closed and circulation may be maintained using the booster **27** and choke **28** lines.

Alternatively, the method may be utilized for running casing or liner to reinforce and/or drill the wellbore **90**, or for assembling work strings to place downhole components in the wellbore.

FIGS. **6A-6D** illustrates a first alternative flow sub **300** for use with the clamp **200**, according to another embodiment of the present disclosure. The first alternative flow sub **300** may include the housing **105**, a bore valve **310**, a bore valve actuator, and a side port valve **320**.

The bore valve **310** may include the ball **111**, the seat **112**, a body, such as a body **109**, **313**, and the fastener (not shown, see fastener **114**). The body **109**, **113** may include one or more sections, such as the upper section **109** and a lower **313** section. The lower body section **313** may be disposed within the housing **105** and connected thereto. The lower body section **313** may have the lip **113p** and the threaded coupling for connection to the housing **105**.

The port valve **320** may include a closure member, such as a sleeve **321**, and the seal mandrel **122**. The valve sleeve **321** may be disposed within the housing **105** and longitudinally moveable relative thereto between an open position (FIG. **7D**) and a closed position (FIG. **6A**) by the clamp **200**. The sleeve may include an upper portion **321u**, a lower portion **121b**, and a lug **121c** disposed between the upper and lower portions.

The bore valve actuator may be mechanical and include a cam **315**, the followers **118**, and a combined linkage and a toggle. The cam **315** may interact with the valve sleeve **321** via the combined linkage and toggle. The combined linkage and toggle may include one or more (two shown) pins **316**, inner J-slots **321j**, and outer J-slots **313j**. Each linkage/toggle pin **316** may be threaded and connected to the cam **315** by being received in a threaded socket thereof. A shank of each linkage/toggle pin **316** may extend through the

respective outer J-slot **313j** formed through a wall of the lower body section **313** and into the respective inner J-slot **321s** formed through a wall of the sleeve upper portion **321u**.

Each outer J-slot **313j** may have an upper straight longitudinal portion, a lower pin receiver portion, and a mid inclined portion connecting the upper and lower portions. Each inner J-slot **321j** may have an upper straight longitudinal portion and a lower pin articulation portion. Each pin articulation portion may have an upper tangential wall and a lower inclined wall forming a portion oversized relative to a shank diameter of the linkage/toggle pin **316** to accommodate movement of the pin in the inclined portion of the respective outer J-slot **313j**. To also accommodate movement of the linkage/toggle pin **316** in both respective J-slots **313j**, **321j**, the valve sleeve **321** may be torsionally restrained from rotating relative to the cam **315** and lower body section **313** by: seal friction, friction with the engaged clamp yoke **213**, and/or each of the lug **121c** and the clamp yoke having mating anti-rotation features.

During an upstroke (FIGS. **7A-7D**) of the first alternative flow sub **300**, the combined linkage and toggle may longitudinally connect the cam **315** and the valve sleeve **321** after allowing a predetermined amount of longitudinal movement therebetween. A stroke of the cam **315** may be less than a stroke of the sleeve **321**, such that when coupled with the lag created by the combined linkage and toggle, the bore valve **310** and the port valve **320** may never both be fully closed simultaneously (FIG. **7A**). During a downstroke (FIGS. **7E-7I**) of the first alternative flow sub **300**, the combined linkage and toggle may longitudinally connect the cam **315** and the sleeve **321** before allowing a predetermined amount of longitudinal movement therebetween such that the bore valve **310** and the port valve **320** may never both be fully closed simultaneously (FIG. **7I**).

FIGS. **7A-7I** illustrates operation of the first alternative flow sub **300**. Once it is necessary to extend the drill string **10**, drilling may be stopped by stopping advancement and rotation **16** of the top drive **5** and removing weight from the drill bit **15**. A spider (not shown) may then be operated to engage the drill string **10**, thereby longitudinally supporting the drill string **10** from the rig floor **4**. The clamp **200** may then be transported to the first alternative flow sub **300** and closed around the flow sub lower housing section. The PLC **75** may then operate the band actuator **220**, thereby tightening the clamp **200** into engagement with the flow sub lower housing. The MSV **238** may be manually opened and then the rig crew may evacuate the rig floor **4**. After testing, the PLC **75** may then operate the port valve actuator **210**, thereby rotating the lead screw **218** and raising the yoke **213**.

Referring specifically to FIG. **7A**, when moved upwardly by the yoke **213**, the valve sleeve **321** may move longitudinally relative to the cam **315** until the inclined portions of the inner J-slots **321j** engage the linkage/toggle pins **316**, thereby coupling the sleeve and the cam. Due to the lag, discussed above, drilling fluid **60d** may momentarily flow into the drill string **10** through both the port valve **320** and the bore valve **310**.

Referring specifically to FIG. **7B**, continued upward movement of the valve sleeve **321** may raise the linkage/toggle pins **316** from the receiver portions of the outer J-slots **313j** and into the mid inclined portions thereof, thereby allowing the cam **315** to move upward and be rotated due to the pins sliding along the inclined lower walls of the inner J-slots **321j**. The rotation of the cam **315** may be about a longitudinal axis of the housing **105** and may also cause rotation of the ball **111** therewith due to the engagement of

the followers **118** with the ball cam profile. This rotation may not affect opening or closing of the bore valve **310** since rotation of the ball **111** between the open and closed positions may be about a transverse axis of the housing **105**. Also at this position, closing of the bore valve **310** has commenced due to the transverse rotation of the ball **111** in response to the upward movement of the cam **315**.

Referring specifically to FIG. 7C, upward movement of the sleeve **321** and upward and rotational movement of the cam **315** may continue, thereby further closing the bore valve **310**. The rotation of the cam **315** may be halted by engagement of the upper straight portions of the outer J-slots **313j** with the linkage/toggle pins **316** and this engagement may be accommodated by engagement of bottoms of the inner J-slots **321j** with the pins.

Referring specifically to FIG. 7D, upward movement of the sleeve **321** and cam **315** may continue, thereby fully closing the bore valve **310**. The upward movement may be accommodated by sliding of the linkage/toggle pins **316** along the straight upper portions of the outer J-slots **313j**. The upward movement may be halted by engagement of an upper shoulder of the yoke **213** with an upper shoulder of the stem portion **201s** at which point the port valve **320** is fully open. The top drive **5** may then be operated to disconnect from the first alternative flow sub **300** and to hoist a stand from pipe rack **17**. The top drive **5** may continue to be operated to connect to the first alternative flow sub **300** of the retrieved stand. The top drive **5** may then be operated to connect a lower end of the stand to the first alternative flow sub **300** of the drill string **10**. Drilling fluid **60d** may continue to be injected into the open port valve **320** during adding of the stand. Once the stand has been added to the drill string **10**, the PLC **75** may pressurize the added stand **10s** and then reverse operate the port valve actuator **210**, thereby counter-rotating the lead screw **218** and lowering the yoke **213**.

Referring specifically to FIG. 7E, lowering of the yoke **213** may cause downward movement of the valve sleeve **321** which may be free to move a short distance relative to the cam **315** due to the oversizing of the pin articulation portions of the inner J-slots **321j**. The free movement may be halted by engagement of the tangential upper walls of the inner J-slots **321j** with the linkage/toggle pins **316**.

Referring specifically to FIG. 7F, downward movement of the valve sleeve **321** and cam **315** may commence opening of the bore valve **310**. The downward movement may be accommodated by sliding of the linkage/toggle pins **316** along the straight upper portions of the outer J-slots **313j**. The downward movement may be halted by engagement of the linkage/toggle pins **316** with the mid inclined portions of the outer J-slots **313j**.

Referring specifically to FIG. 7G, continued downward movement of the valve sleeve **321** may drive the linkage/toggle pins **316** along the mid inclined portions of the outer J-slots **313j**, thereby counter rotating the cam **315** about the longitudinal axis and moving the pins relative to the tangential upper walls of the inner J-slots **321j**. Opening of the bore valve **310** may also continue.

Referring specifically to FIG. 7H, downward movement of the valve sleeve **321** and downward and rotational movement of the cam **315** may continue, thereby further opening the bore valve **310**. The rotation of the cam **315** may be halted by engagement of the linkage/toggle pins **316** with the pin receiver portions of the outer J-slots **313j** and this engagement may align the pins with the straight portions of the inner J-slots **321j**.

Referring specifically to FIG. 7I, downward movement of the valve sleeve **321** and cam **315** may continue until a

bottom of the cam **315** engages the top face of the lip **113p** at which point the bore valve **310** may be fully open. Due to the lag, discussed above, drilling fluid **60d** may momentarily flow into the drill string **10** through both the port valve **320** and the bore valve **310**. The valve sleeve **321** may move then move downward relative to the cam **315** until tops of the inner J-slots **321j** engage the linkage/toggle pins **316**, at which point the port valve **320** is fully closed.

The PLC **75** may then relieve pressure from the clamp inlet **207**. The rig crew may then return to the rig floor **4** and close the MSV **238**. The clamp **200** may then be opened and transported away from the first alternative flow sub **300**. The spider may then be operated to release the drill string **10**. Once released, the top drive **5** may be operated to rotate **16** the drill string **10**. Weight may be added to the drill bit **15**, thereby advancing the drill string **10** into the wellbore **90** and resuming drilling of the wellbore. The process may be repeated until the wellbore **90** has been drilled to total depth or to a depth for setting another string of casing.

FIGS. 8A-8D illustrates a second alternative flow sub **400**, according to another embodiment of the present disclosure. The second alternative flow sub **400** may include a tubular housing **405**, a bore valve **410**, a port valve actuator, and a side port valve **420**. The housing **405** may include one or more sections, such as an upper section **405u** and a lower **405b** section, each section connected together, such as by a threaded connection. An outer diameter of the housing **405** may correspond to the tool joint diameter of the drill pipe **10p** to maintain compatibility with the RCD **26**. The housing **405** may have a central longitudinal bore formed there-through and a radial flow port **401** formed through a wall thereof in fluid communication with the bore (when the port valve is open) and located at a side of the lower housing section **405b**. Alternatively, the side port **401** may be inclined between the radial and longitudinal axes of the housing **405**. The housing **405** may also have a threaded coupling at each longitudinal end, such as box **406b** formed in an upper longitudinal end and a pin **406p** formed on a lower longitudinal end, so that the housing may be assembled as part of the drill string **10**. Except for seals and where otherwise specified, the second alternative flow sub **400** may be made from a metal or alloy, such as steel, stainless steel, or a nickel based alloy. Seals may be made from an elastomer or elastomeric copolymer and may include backup rings and/or energizing springs.

The upper housing section **405u** may have an upper shoulder **403u** formed in an inner surface thereof and adjacently below the box **406b**. The lower housing section **405b** may have a lower shoulder **403b** formed in an inner surface thereof and adjacently below the side port **401**. A length of the housing **405** may be equal to or less than the length of a standard joint of drill pipe **10p**. Additionally, the housing **405** may be provided with one or more pup joints (not shown) in order to provide for a total assembly length equivalent to that of a standard joint of drill pipe **10p**. The pup joints may include one or more centralizers (not shown) (aka stabilizers) or the centralizers may be mounted on the housing **405**.

The bore valve **410** may include a closure member, such as a ball **411**, a seat **412**, and a body **409**. The body **409** may be disposed within the housing **405** and include an upper section **409u** and a lower section **409b**. A first seal **424a** may be disposed between the upper housing section **405u** and the upper body section **409u** and a second seal **424b** may be disposed between the upper body section **409u** and the lower body section **409b** to isolate the interfaces thereof. The upper body section **409u** may have a recess formed in an

inner surface thereof and extending from a bottom thereof for receiving an upper portion of the lower body section **409b**. The lower body section **409b** may have one or more (three shown) equalization ports formed through a wall thereof adjacently above the second seal **424b**.

The seat **412** may include a seal and a gland. The lower body section **409b** may have a recess formed in an outer surface thereof and extending from a bottom thereof for receiving the seat **412**. The seat seal may be coupled to the lower body section **409b**, such as by a lip and by being disposed between the lower body section **409b** and ball **411**. The seat seal may be connected to the gland by being molded thereon and/or by a lip and groove. The seat seal may be annular and have a tapered inner surface conforming to an outer surface of the ball **411** for sealing engagement therewith. The seat seal may be pressed against the ball **411** by engagement of a top of the upper body section **409u** with the upper housing shoulder **403u** and engagement of a top of the lower body section **409b** with a shoulder formed in an inner surface of the upper body section.

The ball **411** may be disposed in the housing **405** between the seat **412** and the port valve **420** and rotatable about a transverse axis of the housing **405**. The ball **411** may be operable between an open position (FIG. **8A**) and a closed position (FIG. **8B**) by one or more pivot pins **416**, **417**. The ball **411** may have a bore formed therethrough corresponding to the housing bore and aligned therewith in the open position. A wall of the ball **411** may close an upper portion of the housing bore in the closed position and the ball may be engaged with the seat seal in and between the positions.

One of the pivot pins may be a drive pin **416** and the other may be an idler pin **417**. Each pin **416**, **417** may be received by a respective socket formed through a wall of the lower housing section **405b**. Each pin **416**, **417** may have a head portion and a shank portion. Each shank portion may be received by a respective socket **411s** formed in an outer surface of the ball **411**. Each shank portion and ball socket **411s** may have a mating torsional profile, such as polygonal, formed in a mating surface thereof (outer surface for shank portion and inner surface for ball socket). The drive pin **416** may also have a torsional profile, such as polygonal, formed in an outer face thereof for receiving a drive shaft of the first alternative clamp. Each pin **416**, **417** may be supported for rotation relative to the housing by a respective radial bearing **418d,i**. Each bearing **418d,i** may include an inner sleeve press fit onto a recess formed in an outer surface of the respective head portion and an outer sleeve connected to the respective housing socket, such as by a threaded connection. Each outer sleeve may have a lip formed in an inner surface thereof for trapping the respective pin in the respective housing socket. Each pin **416**, **417** may have a groove formed in an outer surface of the respective head portion for receiving a respective seal **419d,i**. Each seal **419d,i** may engage a respective seal bore formed in the respective housing socket.

The port valve **420** may include a closure member, such as a sleeve **421**, a port seal **422**, and a pair of seals **424c,d** disposed between the sleeve and the lower housing section **405b** and straddling the side port **401** to isolate longitudinal interfaces thereof. The valve sleeve **421** may have a port **421p** formed through a wall thereof corresponding to the side port **401** and a groove **421v** formed in an outer surface thereof adjacent to the sleeve port. The port seal **422** may be disposed in the groove **421v** and sealingly engage an inner surface of the lower housing section **405b** to isolate a circumferential interface thereof. The valve sleeve **421** may be rotatable about a longitudinal axis of the housing **405**

between an open position (FIG. **8B**) and a closed position (FIG. **8A**) by the port valve actuator. A wall of the valve sleeve **421** may close the side port **401** in the closed position and the sleeve port **421p** may be aligned with the side port **401** in the open position. The valve sleeve **421** may be longitudinally retained in the housing **405** by being trapped between the ball **411** and the housing lower shoulder **403b**. A recess **404** may be formed in an outer surface of the lower housing section **405b** adjacent to the side port **401** for receiving a stab connector formed at an end of an inlet of a first alternative clamp (not shown).

The port valve actuator may be mechanical and include a pair of meshing gear profiles **411g**, **421g**. The ball **411** may have one of the gear profiles **411g** formed in an outer surface thereof concentric with one of the sockets **411s**. A flat **411f** may be formed in an outer surface of the ball adjacent to the ball gear profile to accommodate meshing with the other gear profile **421g** formed in a top of the valve sleeve **421**. A flat **421f** may be formed in the top of the valve sleeve **421** to accommodate the spherical outer surface of the ball **411** in mating of the gear profiles **411g**, **421g**. Each gear profile **411g**, **421g** may include a series of bevel teeth and the profiles may have orthogonal axes to convert the rotation of the ball **411** about the transverse axis into rotation about the longitudinal axis for operation of the valve sleeve **421**. Each gear profile **411g**, **421g** may extend almost one hundred eighty degrees about the respective axis thereof. The gear profiles may have a ratio (ball/sleeve) of less than one such that for a quarter turn to move the ball between the positions, the valve sleeve **421** is rotated more than a quarter turn, such as one-third of a turn, to move the sleeve between the positions.

In operation, the first alternative clamp may be installed on the housing **405** in a similar fashion as the clamp **200** except that the first alternative clamp may have a drive shaft instead of the reciprocating yoke **213**. The drive shaft may be stabbed into the drive pin profile during installation of the first alternative clamp. The PLC **75** may then operate the actuator motor **215** to rotate the drive shaft one quarter turn to shift the second alternative flow sub **400** from the top injection mode (FIG. **8A**) to the bypass mode (FIG. **8B**) and then operate the actuator motor **215** to counter rotate the drive shaft one-quarter turn to shift the second alternative flow sub back to the top injection mode. Alternatively, the second alternative flow sub **400** may be manually shifted between the modes.

FIGS. **9A-9D** illustrates a third alternative flow sub **500**, according to another embodiment of the present disclosure. The third alternative flow sub **500** may be similar to the second alternative flow sub **400** except the bore valve **510** has been decoupled from the port valve **520**. The third alternative flow sub **500** may include a gear, such as a bevel gear **516**, instead of having the gear profile **411g** on the ball **511**. The bevel gear **516** may mesh with gear profile **521g** formed in a top of valve sleeve **521** and the valve sleeve top may have a flat **521f** or the entire top may have the gear profile. A spacer sleeve **513** may accommodate inclusion of the gear **516**. The third alternative flow sub **500** may further include a drive pin **516** similar to drive pin **416** for operation of the bevel gear **516**, radial bearing **518**, and seal **519**.

In operation, a second alternative clamp (not shown) may be installed on housing **505** in a similar fashion as the first alternative clamp except that the second alternative clamp may have a second drive shaft in addition to the (first) drive shaft for independent operation of the port valve **510**. The second drive shaft may be stabbed into the profile of the drive pin **516** during installation of the second alternative

clamp. The PLC 75 may then operate a second actuator motor to rotate the second drive shaft before closing of the bore valve 510 when shifting from the top injection mode (FIG. 9A) to the bypass mode (FIG. 9B) and counter rotate the second drive shaft after opening of the bore valve when shifting back to the top injection mode to ensure that both valves 510, 520 are never closed simultaneously. Alternatively, the third alternative flow sub 500 may be manually shifted between the modes.

FIGS. 10A-10F illustrates a fourth alternative flow sub 600, according to another embodiment of the present disclosure. The fourth alternative flow sub 600 may include a tubular housing 605 and a combined bore and port valve 610. The housing 605 may include one or more sections, such as an upper section 605_u and a lower 605_b section, each section connected together, such as by a threaded connection. An outer diameter of the housing 605 may correspond to the tool joint diameter of the drill pipe 10_p to maintain compatibility with the RCD 26. The housing 605 may have a central longitudinal bore formed therethrough and a radial flow port 601 formed through a wall thereof in fluid communication with the bore (when the port valve is open) and located at a side of the lower housing section 605_b. Alternatively, the side port 601 may be inclined between the radial and longitudinal axes of the housing 605. The housing 605 may also have a threaded coupling at each longitudinal end, such as box 606_b formed in an upper longitudinal end and a pin 606_p formed on a lower longitudinal end, so that the housing may be assembled as part of the drill string 10. Except for seals and where otherwise specified, the fourth alternative flow sub 600 may be made from a metal or alloy, such as steel, stainless steel, or a nickel based alloy. Seals may be made from an elastomer or elastomeric copolymer and may include backup rings and/or energizing springs.

The upper housing section 605_u may have an upper shoulder 603_u formed in an inner surface thereof and adjacently below the box 606_b. The lower housing section 605_b may have a lower shoulder 603_b formed in an inner surface thereof and adjacently below the side port 601. A recess 604 may be formed in an outer surface of the lower housing section 605_b adjacent to the side port 601 for receiving a stab connector formed at an end of an inlet of a third alternative clamp (not shown). A length of the housing 605 may be equal to or less than the length of a standard joint of drill pipe 10_p. Additionally, the housing 605 may be provided with one or more pup joints (not shown) in order to provide for a total assembly length equivalent to that of a standard joint of drill pipe 10_p. The pup joints may include one or more centralizers (not shown) (aka stabilizers) or the centralizers may be mounted on the housing 605.

The combined bore and port valve 610 may include a closure member, such as a three-way ball 611, a seat 612, and a body 609. The body 609 may be disposed within the housing 605 and include an upper section 609_u, a mid section 609_m, and a lower cage 613. A first seal 624_a may be disposed between the upper housing section 605_u and the upper body section 609_u, a second seal 624_b may be disposed between the cage 613 and the lower body section 609_b above the side port 601, a third seal may be disposed between the cage 613 and the mid body section 609_m, and a fourth seal 624_d may be disposed between the cage 613 and the lower body section 609_b below the side port to isolate the interfaces thereof. The upper body section 609_u may have a recess formed in an inner surface thereof and extending from a bottom thereof for receiving an upper portion of the mid body section 609_m. The cage 613 may have a recess formed in an inner surface thereof and extend-

ing from a top thereof for receiving a lower portion of the mid body section 609_m. The mid body section 609_m may have one or more (three shown) equalization ports formed through a wall thereof adjacently above the third seal 624_c.

The seat 612 may include a seal and a retainer. The mid body section 609_m may have a recess formed in an inner surface thereof and extending from a bottom thereof for receiving the seat retainer. The seat seal may be coupled to the mid body section 609_m, such as by a lip and groove. The seat seal may be connected to the retainer by being molded thereon and/or by a lip and groove. The seat seal may be annular and have a tapered inner surface conforming to an outer surface of the ball 611 for sealing engagement therewith. The seat seal may be pressed against the ball 611 by engagement of a top of the upper body section 609_u with the upper housing shoulder 603_u and engagement of a top of the mid body section 609_m with a shoulder formed in an inner surface of the upper body section.

The three-way ball 611 may be disposed in the cage 613 via a window 613_w formed through a wall thereof. The three-way ball 611 may be aligned with the side port 601. The three-way ball 611 may be rotatable relative to the cage 613 and the housing 605 about a transverse axis of the housing and between a top injection position (FIGS. 10A and 10C) and a bypass position (FIG. 10B) by pivot pins 616, 617. The three-way ball 611 may have a bore formed therethrough corresponding to the housing bore and aligned therewith in the top injection position while a wall thereof closes the side port 601. The three-way ball 611 may further have a side opening formed by carving nearly half the wall therefrom leaving only a seal flange 611_f extending around the ball bore. In the bypass position, a wall of the three-way ball 611 may close an upper portion of the housing bore while the side opening may be aligned with the housing bore, thereby providing a flow path through the ball via the ball bore and the side opening. The seat seal may engage the seal flange 611_f in the top injection position and the ball wall in the bypass position.

The cage 613 may have a port 613_p formed through a wall thereof corresponding to the side port 601 and a groove 613_v formed in an inner surface thereof adjacent to the sleeve port. A port seal 622 may be disposed in the groove 613_v and sealingly engage the ball wall in the top injection position to isolate a circumferential interface thereof. The port 613_p may be located at a side of the cage 613 opposite to the window 613_w. The cage 613_h may also have a pair of holes 613_h formed through a wall thereof, located at opposite sides thereof, and spaced ninety degrees from the port 613_p and window 613_w.

Each pin 616, 617 may be received by a respective socket formed through a wall of the lower housing section 605_b. Each pin 616, 617 may have a head portion and a shank portion. Each shank portion may extend through the respective hole 613_h and be received by a respective socket 611_s formed in an outer surface of the ball 611. Each shank portion and ball socket 611_s may have a mating torsional profile, such as polygonal, formed in a mating surface thereof (outer surface for shank portion and inner surface for ball socket). The drive pin 616 may also have a torsional profile, such as polygonal, formed in an outer face thereof for receiving a drive shaft of the third alternative clamp. Each pin 616, 617 may be supported for rotation relative to the housing by the respective radial bearing 418_{d,i}. Each pin 616, 617 may have a groove formed in an outer surface of the respective head portion for receiving the respective seal 419_{d,i}. Extension of the pins 616, 617 through the holes 613_h may also maintain alignment of the cage port 613_p

with the side port 601. A quarter turn/counter-turn of the drive pin 616 may rotate the three-way ball 611 between the positions.

In operation, the third alternative clamp may be installed on the housing 605 in a similar fashion as the clamp 200 except that the third alternative clamp may have a drive shaft instead of the reciprocating yoke 213. The drive shaft may be stabbed into the drive pin socket during installation of the first alternative clamp. The PLC 75 may then operate the actuator motor 215 to rotate the drive shaft one quarter turn to shift the fourth alternative flow sub 600 from the top injection mode to the bypass mode and then operate the actuator motor 215 to counter rotate the drive shaft one-quarter turn to shift the fourth alternative flow sub back to the top injection mode. Alternatively, the fourth alternative flow sub 600 may be manually shifted between the modes.

FIG. 11A illustrates a fourth alternative clamp 700, according to another embodiment of the present disclosure. The fourth alternative clamp 700 may be similar to the clamp 200 except for the addition of one or more proximity sensors 701, 702 to the port valve actuator. Although shown engaged with the flow sub 100, the fourth alternative clamp 700 may also be used with the first alternative flow sub 300. Each proximity sensor 701, 702 may be mounted in the bracket 703 at opposite ends thereof so as to be facing the path of the metallic yoke 213. The proximity sensors may be in electrical communication with the PLC 75 via a flexible electric cable to accommodate transport of the fourth alternative clamp 700.

FIGS. 11B and 11C illustrate proximity sensors 701, 702 of the fourth alternative clamp 700. Each proximity sensor 701, 702 may be inductive and include a coil 705, an oscillator 706, a voltage regulator 707, a trigger 708, and a switch 709. Each oscillator 706, voltage regulator 707, trigger 708, and switch 709 may be enclosed in a respective housing 710 and each coil 705 may be wound in a recessed sensing face of the respective sensor 701, 702. Each coil 705, oscillator 706, voltage regulator 707, trigger 708, and switch 709 may be electrically interconnected, such as by leads or by being mounted onto a printed circuit board.

Once the fourth alternative clamp 700 has been engaged with and tightened around the flow sub 100, the PLC 75 may operate the proximity sensors 701, 702 to emit an electromagnetic field 711 into the path of the metallic yoke 213. As the metallic yoke 213 reaches the end of one of the strokes (downstroke shown), eddy currents may circulate therein. The eddy currents may cause a load on the respective oscillator 706, thereby decreasing the amplitude of the electromagnetic field 711 until the respective trigger 708 detects a lower threshold amplitude. Once the threshold amplitude is detected, the trigger 708 may throw the respective switch 709 which is detected by the PLC 75. As the metallic yoke 213 begins the upstroke, the respective trigger 708 may detect an increase in the amplitude of the electromagnetic field 711 and throw the respective switch 709 back to the default position once an upper threshold amplitude is detected.

Alternatively, the proximity sensors 701, 702 may instead be mounted in the body 201 at opposite ends thereof so as to be facing the path of the metallic yoke 213. Alternatively, each proximity sensor 701, 702 may include a separate transmitting and receiving coil instead of the respective transceiver coil 705. Alternatively, each proximity sensor 701, 702 may be Hall effect, ultrasonic, or optical or be a linear variable differential transformer (LVDT).

FIGS. 12A and 12B illustrate a fifth alternative flow sub 720, according to another embodiment of the present dis-

closure. The fifth alternative flow sub 720 may be similar to either the flow sub 100 or the first alternative flow sub 300 except for including an alternative housing 721. The alternative housing 721 may be tubular and include the upper section 105u and a lower 721b section, each section connected together, such as by a threaded connection. The alternative housing 721 may have a central longitudinal bore formed therethrough and the radial flow port 101 formed through a wall thereof in fluid communication with the bore (when the port valve is open) and located at a side of the lower housing section 721b. The window 102 may be formed through a wall of the lower housing section 721b and may extend a length corresponding to a stroke of the port valve 120.

The lower housing section 721b may have an upper portion 722u, a mid portion 722m, and a lower threaded coupling, such as a pin 722p, for assembly with the drill string 10. An outer diameter of the upper portion 722u and the pin 722p may correspond to the tool joint diameter of the drill pipe 10p and an outer diameter of the mid portion 722m may correspond to the nominal diameter of the drill pipe 10p. The lower housing section 721b may be manufactured by welding the upper portion 722u and the pin 722p to respective upset ends of the mid portion 722m. A length of the housing 721 may correspond to, such as being equal to or slightly greater than, the length of a standard joint of drill pipe 10p. To assemble a stand with fifth alternative flow sub 720, the fifth alternative flow sub may replace one of the joints of drill pipe 10p. As compared to forming the stand 10s using the flow sub 100, the threaded connection between the pin 106p and the upper joint of drill pipe 10p may be eliminated, thereby reducing the increase in length compared to a stand formed without the flow sub.

FIG. 13A illustrates an iron roughneck 730 for use with the flow sub 100 instead of the clamp 200, according to another embodiment of the present disclosure. The iron roughneck 730 may also be used with the first alternative flow sub 300 or the fifth alternative flow sub 720. The iron roughneck 730 may include a frame 731, a wrenching tong 732, a backup tong 733, a spinner 734, and a flow sub tong 735.

The wrenching tong 732 may be a disc with an opening (not shown) through the center thereof for receiving a bottom coupling of the stand 10s to be added to the drill string 10 and a recess cut from the edge to the opening at the center. The wrenching tong 732 may be provided with one or more, such as a pair, of pinion drives 736 arranged opposite each other at the periphery of the disc, equally spaced either side of the recess. Each pinion drive may include a drive motor, a drive shaft, and a pinion attached to the drive shaft.

The back-up tong 733 may be located beneath the wrenching tong 732. The back-up tong 733 may also be a disc with similar dimensions to the wrenching tong 732. The back-up tong may also have an opening through the center and a recess from the edge to the opening at the center for receiving the upper housing section 105u. The opening and recess may correspond to the opening and recess of the wrenching tong 732 when the back-up tong 733 and the wrenching tong are aligned.

A plurality of guide rollers or other guide elements may be spaced around the edge of the wrenching tong 732 in order to maintain the alignment of the wrenching tong with the back-up tong 733. A gear may be formed around the periphery of the back-up tong 733, broken by the recess thereof. The gear may mesh with the pinions attached to the drive motors on the wrenching tong 732, so that when the

drive motors drive the drive shafts and gears, the wrenching tong rotates relative to the back-up tong 733.

The back-up tong 733 may have a plurality of roller bearings, upon which the wrenching tong 732 is placed. The roller bearings may be supported by a thread compensator in order to support the wrenching tong 732 during rotation thereof while accommodating longitudinal displacement of the stand 10s being added relative to the drill string 10 due to screwing together of the threaded couplings.

Each of the wrenching tong 732 and the back-up tong 733 may have one or more, such as three, clamping jaws (not shown) equipped with dies are located therein. The clamping jaws may be driven by the HPU 30h for engagement with the respective bottom coupling of the stand 10s and upper housing section 105u. The iron roughneck 730 may include a hub for receiving flexible hydraulic conduits from the manifold 39 and connecting the clamping jaws thereto. Each jaw may be driven by a piston and chamber assembly carried on the respective tong 732, 733. Each piston may have an end which is secured to the outside edge of the respective tong 732, 733. Each chamber may be connected to the respective jaw, such as by a spherical bearing.

The back-up tong 733 may be mounted to the frame 731. The spinner 734 may be mounted to the frame 731 above the tongs 732, 733 for rotating the bottom coupling of the stand 10s at high speed relative to a rotational speed of the tongs. The spinner may include a friction wheel driven by a motor and the motor may be in communication with the manifold 39 via the hub. The frame 731 may have wheels for rolling along rails of the rig floor 4 and one of the wheels may be driven by a motor in communication with the manifold via the hub.

The flow sub tong 735 may be mounted to the frame 731 beneath the back-up tong 733. The flow sub tong 735 may include a body, the inlet 207, the port valve actuator 210, an automated MSV (not shown), the adapter 231, a video monitoring unit 738, and one or more, such as two, clamping jaws. The body may also be a disc and have an opening through the center and a recess from the edge to the opening at the center for receiving the lower housing section 105b. The inlet 207 may be connected to the body and the port valve actuator 210 may be connected to the body. The clamping jaws may be disposed in the body and driven by the HPU 30h for engagement with the lower housing section 105b which may also pull the inlet 207 toward the lower housing section, thereby stabbing the stab connector 209 into the flow port 101 and engaging the yoke 213 with the lug 121c. Each jaw may be driven by a piston and chamber assembly carried on body. Each piston may have an end which is secured to the outside edge of the body. Each chamber may be connected to the respective jaw, such as by a spherical bearing.

The video monitoring unit 738 may have a video camera and a light source. The video monitoring unit 738 may be mounted on the port valve actuator 210 and be in data communication with the PLC 75, such as by a flexible cable. The PLC 75 may relay video to the driller's console 739 to facilitate alignment and orientation of the flow sub 100 with the iron roughneck 730. The driller's console 739 may be located in the rig control room remote from the rig floor 4 and/or be shielded from mud spray should the flow sub 100 fail.

Alternatively, the back-up tong 733, flow sub tong 735, and spinner 734 may be engaged with a track of the frame 731 and supported therefrom by a linear actuator to allow for vertical movement of the components relative to the frame. Alternatively, the tongs 732, 733, 735 and spinner 734 may

be connected to a telescopic arm instead of the frame 731. The telescopic arm may be similar to the telescopic arm alternative discussed above. Alternatively, the hydraulic components of the iron roughneck 730 may instead be pneumatic or electric. Alternatively, the video monitoring unit 738 may be mounted on the body of the flow sub tong 735.

FIGS. 13B-13D illustrates engagement of the iron roughneck 730 with the flow sub 100. Once it is necessary to extend the drill string 10, drilling may be stopped by stopping advancement and rotation 16 of the top drive 5 and removing weight from the drill bit 15. The driller may operate the drive wheel motor of the iron roughneck 730, thereby propelling the iron roughneck from a stowed location on the rig floor 4 toward the drill string 10. The driller may stop the iron roughneck 730 at a location adjacent to the drill string 10 and activate the video monitoring unit 738. The driller may then operate the drawworks 9 to align the flow sub 100 with the iron roughneck 730 and operate the top drive 5 to orient the flow sub such that the flow port 101 and window 102 face the iron roughneck. The spider may then be operated to engage the drill string 10, thereby longitudinally supporting the drill string 10 from the rig floor 4. The rig crew may evacuate the rig floor 4. The driller may then operate the drive wheel motor such that the flow sub 100 is received into the recesses of the tongs 733, 735 and the clamping jaws of the back-up tong 733 and flow sub tong 735 may be engaged with the flow sub 100. Testing and switching of the flow to the flow sub 100 may proceed as discussed above.

Once the driller has operated the top drive 5 to hoist the stand 10s and operated the drawworks 9 to stab the bottom coupling thereof into the box 106b, the driller may operate the spinner 734 to screw the bottom coupling of the stand into the box. The driller may then operate the jaws of the wrenching tong 732 to engage the stand 10s and operate the drive motors of the iron roughneck 730 to tighten the connection between the stand 10s and the flow sub 100. Switching of the flow back to the top drive and testing may proceed as discussed above. The driller may then operate the iron roughneck 730 to release the flow sub 100 and the rig crew may return to the rig floor 4.

FIGS. 14A and 14B illustrate a rover 750 for use with the flow sub 100 instead of the clamp 200, according to another embodiment of the present disclosure. The rover 750 may also be used with the first alternative flow sub 300 or the fifth alternative flow sub 720. The rover 750 may include a chassis, a drive motor (not shown), wheels, a robotic arm (not shown), an automated clamp, the automated MSV (not shown), the adapter (not shown), the video monitoring unit (not shown), and one or more, such as two, clamping jaws (not shown). The rover 750 may be operated from the driller's console via data link with the PLC 75. The rover 750 may be electrically powered via battery or power cable.

The automated clamp 751 may be similar to the clamp 200 except for having automated jaws (not shown) instead of the band 202, the latch 205, and the band actuator 220. The automated jaws may be operated to engage the lower housing section 105b and to pull the inlet 207 toward the lower housing section, thereby stabbing the stab connector 209 into the flow port 101 and engaging the yoke 213 with the lug 121c. The automated clamp may be mounted to the robotic arm and the robotic arm may be mounted to the chassis. Instead of having to operate the drawworks and top drive to align and orient the iron roughneck 730 with the flow sub 100 before the spider is engaged, the spider may be engaged and the rover 750 may be driven across the rig floor

29

4 into the vicinity of the flow port 101 and window 102. The robotic arm may possess sufficient degrees of freedom, such as six, place the automated clamp around the lower housing section 105b and to align and orient the automated clamp 751 relative to the flow port 101 and window 102.

Alternatively, the robotic arm may be mounted to the rig floor 4 instead of to the chassis. Alternatively, the rover 750 may be autonomously driven by placing one or more beacons in the rig floor 4.

FIGS. 15A and 15B illustrate a handler 760 for use with the clamp 200, according to another embodiment of the present disclosure. The handler 760 may include an arm 761 pivotally connected to the derrick 3 and a harness 762 fastened to the clamp. The clamp 200 may be swung between a stowed position (FIG. 15A) and a ready position (FIG. 15B).

Alternatively, the handler 760 may be automated by adding a linear actuator and replacing the clamp 200 with the automated clamp 751. The linear actuator may be pivotally connected to the derrick 3 and the harness 762 and operable to swing the automated clamp 751 between the ready and stowed positions.

While the foregoing is directed to embodiments of the present disclosure, other and further embodiments of the disclosure may be devised without departing from the basic scope thereof, and the scope of the invention is determined by the claims that follow.

The invention claimed is:

1. A flow sub for use with a drill string, comprising:
 - a tubular housing having a longitudinal housing bore therethrough and a flow port through a wall thereof;
 - a ball disposed in the housing above the flow port, having a ball bore therethrough, and rotatable relative to the housing between an open position where the ball bore is aligned with the housing bore and a closed position where a wall of the ball blocks the housing bore;
 - a seat disposed in the housing above the ball for sealing against the ball wall in the closed position;
 - a sleeve disposed in the housing and movable between an open position where the flow port is exposed to the housing bore and a closed position where a wall of the sleeve is disposed between the flow port and the housing bore; and
 - an actuator operably coupling the sleeve and the ball such that opening the sleeve closes the ball and closing the sleeve opens the ball, the actuator having a cam movable relative to the housing, operably connected to the ball, and releasably connected to the sleeve.
2. The flow sub of claim 1, wherein:
 - the sleeve is longitudinally movable relative to the housing, and
 - the actuator is operable to close the ball after the sleeve is at least partially open and open the ball before the sleeve is fully closed.
3. The flow sub of claim 2, wherein the actuator comprises:
 - the cam longitudinally movable relative to the housing and having a cam socket formed through a wall of the cam;
 - a body disposed adjacently below the ball, connected to the housing, and having a linkage slot and a toggle slot, each slot formed through a wall of the body;
 - a groove formed in an inner surface of the housing;
 - a sleeve slot formed through a wall of the sleeve;
 - a sleeve socket formed through the sleeve wall;

30

a linkage pin fastened to the cam and extending through the linkage slot and into the sleeve slot; and

a toggle pin extending through the cam socket and toggle slot and radially movable relative to the housing and the sleeve between a position engaged with the sleeve socket and a position disengaged from the sleeve socket by interaction with the housing groove.

4. The flow sub of claim 3, wherein:

the sleeve socket is aligned with a bottom of the sleeve slot,

the linkage and toggle pins are aligned, and

the linkage slot and toggle slot have equal widths and lengths.

5. The flow sub of claim 2, wherein the actuator comprises:

the cam longitudinally movable relative to the housing;

a body disposed adjacently below the ball, connected to the housing, and having a body j-slot through a wall of the body;

a sleeve j-slot formed through a wall of the sleeve; and

a pin fastened to the cam and extending through the body j-slot and into the sleeve j-slot.

6. The flow sub of claim 5, wherein the sleeve j-slot has an upper tangential wall and a lower inclined wall forming an oversized portion to accommodate movement of the pin in an inclined portion of the body j-slot.

7. The flow sub of claim 5, wherein:

the ball is rotatable between the positions about a transverse axis of the housing,

the cam and ball are rotatable about a longitudinal axis of the housing to accommodate movement of the pin along the j-slots.

8. The flow sub of claim 1, further comprising a piece of drill pipe connected to the housing and extending a length of the housing to correspond to a length of a joint of standard drill pipe.

9. The flow sub of claim 1, the actuator further comprising:

a body connected to the housing and having a slot formed through a wall of the body; and

a slot formed through a wall of the sleeve.

10. The flow sub of claim 9, the actuator further comprising a pin fastened to the cam and extending through the slot of the body and into the slot of the sleeve.

11. The flow sub of claim 1, wherein the cam is rotatable about a longitudinal axis of the housing and longitudinally movable relative to the housing.

12. A continuous flow system, comprising:

a flow sub comprising:

a tubular housing having a longitudinal housing bore therethrough and a flow port through a wall thereof;

a ball disposed in the housing above the flow port, having a ball bore therethrough, and rotatable relative to the housing between an open position where the ball bore is aligned with the housing bore and a closed position where a wall of the ball blocks the housing bore;

a seat disposed in the housing above the ball for sealing against the ball wall in the closed position; and

a sleeve disposed in the housing and movable between an open position where the flow port is exposed to the housing bore and a closed position where a wall of the sleeve is disposed between the flow port and the housing bore;

an inlet for injecting fluid into the flow port and operable to seal against a surface of the housing adjacent to the flow port; and

31

an automated port valve actuator operable to move the sleeve, wherein:
the housing further has a window formed through the wall thereof and exposing an outer surface of the sleeve, and
the port valve actuator engages the sleeve through the window as the inlet engages the housing.

13. The system of claim 12, wherein:
the sleeve has a lug formed in an outer surface thereof, the port valve actuator comprises:
a yoke for engaging the lug; and
a pair of proximity sensors, each sensor facing a path of the yoke.

14. The system of claim 13, wherein:
the yoke is metallic, and
the proximity sensors are each inductive.

15. The system of claim 13, wherein:
the yoke has a nut portion engaged with a lead screw, the port valve actuator further comprises:
a hydraulic motor; and
a gear train operably coupling the lead screw to the hydraulic motor.

16. The system of claim 12, wherein:
the inlet and port valve actuator are connected to a body of a clamp,
the clamp further comprises:
a band; and
a latch operable to fasten the band to the body; and
an automated band actuator operable to tension or loosen the band, body, and latch.

17. The system of claim 12, wherein:
the inlet and port valve actuator are connected to a body of a flow sub tong, and
the flow sub tong is configured to engage the housing.

18. The system of claim 17, wherein:
the flow sub tong is mounted to a frame of an iron roughneck, and
the iron roughneck further comprises:
a backup tong mounted to the frame;
a wrenching tong supported by the backup tong and rotatable relative thereto; and
a spinner mounted to the frame.

19. The system of claim 12, wherein:
the inlet and port valve actuator are connected to a body of an automated clamp, and
the automated clamp is configured to engage the housing, the automated clamp is carried on a chassis of a rover, and the rover further comprises a plurality of wheels and a drive motor.

20. The system of claim 12, wherein:
the inlet and port valve actuator are connected to a body of a clamp, and
the clamp is suspended from a derrick of a drilling rig by a harness and an arm.

21. The system of claim 12, the flow sub further comprising an actuator operably coupling the sleeve and the ball such that opening the sleeve closes the ball and closing the sleeve opens the ball, the actuator having a cam movable relative to the housing, operably connected to the ball, and releasably connected to the sleeve.

22. The system of claim 21, the actuator of the flow sub further comprising:
a body connected to the housing and having a slot formed through a wall of the body; and
a slot formed through a wall of the sleeve.

32

23. A method for drilling a wellbore, comprising:
drilling the wellbore by injecting drilling fluid into a top of a tubular string disposed in the wellbore at a first flow rate and rotating a drill bit, wherein:
the tubular string comprises:
the drill bit disposed at a bottom thereof,
tubular joints connected together, and
a flow sub disposed at a top thereof, wherein the flow sub comprises:
a tubular housing having a longitudinal housing bore therethrough and a flow port through a wall thereof;
a ball disposed in the housing above the flow port, having a ball bore therethrough, and rotatable relative to the housing between an open position where the ball bore is aligned with the housing bore and a closed position where a wall of the ball blocks the housing bore;
a seat disposed in the housing above the ball for sealing against the ball wall in the closed position;
a sleeve disposed in the housing and movable between an open position where the flow port is exposed to the housing bore and a closed position where a wall of the sleeve is disposed between the flow port and the housing bore; and
an actuator operably coupling the sleeve and the ball such that opening the sleeve closes the ball and closing the sleeve opens the ball, the actuator having a cam movable relative to the housing, operably connected to the ball, and releasably connected to the sleeve,
the drilling fluid exits the drill bit and carries cuttings from the drill bit, and
the cuttings and drilling fluid (returns) flow from the drill bit via an annulus defined between the tubular string and the wellbore;
moving the sleeve to the open position; and
injecting the drilling fluid into the flow port at a second flow rate while adding a stand to the tubular string, wherein injection of drilling fluid into the tubular string is continuously maintained between drilling and adding the stand to the tubular string.

24. The method of claim 23, wherein the flow sub automatically rotates the ball to the closed position in response to moving the sleeve to the open position.

25. The method of claim 23, further comprising rotating the ball to the closed position after moving the sleeve to the open position and before adding the stand.

26. The method of claim 23, the actuator of the flow sub further comprising:
a body connected to the housing and having a slot formed through a wall of the body; and
a slot formed through a wall of the sleeve.

27. The method of claim 26, the actuator of the flow sub further comprising a pin fastened to the cam and extending through the slot of the body and into the slot of the sleeve.

28. The method of claim 23, wherein the cam is rotatable about a longitudinal axis of the housing and longitudinally movable relative to the housing.